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THE DEMAND FOR COAL BY THE ELECTRICAL GENERATION
INDUSTRY IN ALBERTA

by

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A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES
IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE DEGREE
OF MASTER OF ARTS

DEPARTMENT OF ECONOMICS

EDMONTON, ALBERTA

APRIL 13, 1967

UNIVERSITY OF ALBERTA
FACULTY OF GRADUATE STUDIES

The undersigned certify that they have read,
and recommend to the Faculty of Graduate Studies for
acceptance, a thesis entitled

THE DEMAND FOR COAL BY THE ELECTRICAL
GENERATION INDUSTRY IN ALBERTA

submitted by Dennis M. Paproski in partial fulfillment
of the requirements for the degree of Master of Arts.

ABSTRACT

The coal mining industry in Alberta experienced a steady decline in sales and output from the end of World War II until 1961. This situation developed as a result of both technological change and the improved competitive position of alternative sources of energy. The availability of relatively low cost oil, natural gas and diesel fuel resulted in the loss to the coal industry in Alberta of its two major markets; the 'railroad' and the 'space-heating' markets.

At the same time technological improvements in thermal electric plants using coal as a fuel encouraged electrical utility companies in Alberta to exploit the large fields of coal that can be mined by highly efficient strip-mine techniques. The use of coal as a fuel in thermal electric generation has been one of the two major reasons for the increased production of coal in Alberta since 1961. The second major market for Alberta coal is the iron and steel industry in Japan. The retention of this latter market, however, depends upon subventions on coal movement by the Canadian Federal Government and the international competitive position of Alberta coal relative to other foreign suppliers in the Japanese market. The statistics and other information available on this subject are scarce.

On the other hand, the demand for coal by the electrical generation industry in Alberta is largely determined by factors that are either well described in statistics or known to the coal mining and electrical utility industries in Alberta. This thesis, therefore, is based upon a study of these statistics and on the information that has been obtained through interviews and correspondence with the senior personnel of all the major firms in these two industries. Visits to the mines and to the generating plants have added 'first hand' information.

ACKNOWLEDGEMENTS

While all the firms in the coal mining and electrical utility industries have been helpful, I would like to note that Mr. M.M. Williams of Calgary Power and Mr. Wilson Sterling of Canadian Utilities have been most cooperative and helpful. With the cooperation of the firms in these industries, this thesis examines the possible development of coal-fired electric generation in Alberta to the year 1980.

I also acknowledge the debt of gratitude that I owe to Dr. R.A. Pendergast, my thesis advisor, Dr. E.J. Hanson and Dr. W.D. Gainer, all of whom offered suggestions to round-out the study. The financial assistance of the Canadian Federation of Mayors and Municipalities is appreciated, and my secretary, Mrs. Edna Currie, deserves thanks for typing this thesis in addition to her usual heavy typing load.

Above all my wife Margaret and my children deserve credit for their encouragement and support through the years at university.

TABLE OF CONTENTS

	Page
ABSTRACT	iii
ACKNOWLEDGEMENTS	v
TABLE OF CONTENTS	vi
LIST OF TABLES	viii
LIST OF FIGURES	viii

Chapter I	INTRODUCTION	1
	A. Alternative Demands on the Coal Resources of Alberta	2
	a. The Coking Coal Market	3
	b. Markets for Strip-Mined Coal	6
	(i) Household and Industrial Space-Heating	7
	(ii) Industrial and Mining Heat Requirements	8
	(iii) Requirements of the Chemical Industry	9
	B. The Electrical Generation Industry Demand for Alberta Coal	10
Chapter II	THE ALBERTA COAL INDUSTRY, 1945 to 1965	13
	A. The Declining Demand for Coal in the Space-Heating and Railroad Markets.....	15
	a. The Space-Heating Market	15
	b. The Railroad Market	23
	B. Developments in the Demand for Coal by the Electrical Generation Industry	26
Chapter III	MAJOR FACTORS AFFECTING THE DECISION TO INVEST IN COAL-FIRED THERMAL ELECTRIC GENERATING UNITS. THE ALBERTA EXAMPLE	46

	Page
Chapter IV PROJECTED COAL DEMAND BY THE ELECTRICAL GENERATION INDUSTRY IN ALBERTA	67
Chapter V CONCLUSION	78
A. The Effect of Load Factor on Energy Source Consumption	78
a. Load Factor on Hydro Facilities	78
b. Load Factor on Natural Gas Generating Units	81
c. Load Factor on Coal-Fired Generating Units	82
B. Conclusion	83
Appendix	87
Bibliography.....	116

LIST OF TABLES

	Pages
Table 1 The Disposition of Alberta Coal Production ... 1943-1963	14
Table 2 Coal Used in Central Electric Generation Stations in Alberta ... 1949-1964	16
Table 3 Comparative Transport-Transmission Costs	58
Table 4 Present and Anticipated Coal Based Electrical Generation Capacity in Alberta	69
Table 5 Projected Demand for Coal by the Electrical Utility Industry in Alberta ... 1966-1980 .. at 100% Load Factor	72

LIST OF FIGURES

Figure 1 How the Canadian Household Market is Divided Among the Major Competing Fuels	20
Figure 2 Average Coal Rate of Thermal Plants in U.S.A. ...	28
Figure 3 Typical Section of Overburden & Coal Measure Wabamun Coal Mine	35
Figure 4 Variation of Plant Cost With Unit Size	48
Figure 5 Typical Annual Load Duration Curve	51
Figure 6 Forecast of Coal to be Used for Electrical Power Generation in Alberta	73

CHAPTER I

INTRODUCTION

Profound changes have occurred in the energy sector of the Alberta provincial economy during the post-war period. There has been a rapid increase in the production of oil and natural gas during this period but the total output of coal decreased from 8.8 million tons in 1945 to 2.0 million tons in 1961.¹

Since 1961, however, the output of coal has shown a steady increase. This thesis examines the decline in coal production from 1945 to 1961, the reversal of the downward trend since 1961, and the supply and demand factors that have caused the reversal. Based on this examination of the developments in the recent past, the prospects for the coal industry over the next fifteen years are studied. The major area of study involves the potential derived demand for coal on the part of the electrical generation industry in Alberta. Concurrent with this study of the demand factors, technological and supply factors are examined to ascertain the advantages of coal-fired thermal electric plants relative to alternative sources of electrical generation including oil, natural gas, hydro and nuclear sources.

¹ See Table 1, p. 14.

A. Alternative Demands on the Coal Resources of Alberta

The scope of this thesis is limited to a study of coal production in relation to the potential coal demanded on the part of the electrical generation industry in Alberta. By limiting the scope of this study, it has been possible to supplement government statistics with interviews with persons directly involved in the coal and electrical generation industries. In addition, this sector of the economy of Alberta is relatively uncomplicated by supply and demand conditions which arise outside of the province. To be sure, interprovincial electrical grid systems and a broadening market for coal outside of Alberta are possible but, at present and in the near future, the electrical demand in Alberta is and will be met generally by electrical utility companies serving only Alberta.² These companies will use the fuel and hydro resources of Alberta to satisfy the bulk of this demand.

It is not, therefore, because reserves of coal in Alberta are in scarce supply nor because other markets for coal produced in Alberta are insignificant that the scope of this thesis is limited. Indeed, the known 'mineable coal reserves' in Alberta are adequate

² See Appendix A, p. 88 East Kootenay Power electrical sales to Calgary Power are supplied by a plant located at Sentinel, Alta. See Appendix B, p. 92 The proposed interconnection with B.C. Hydro will be an exception to this generality should this interconnection in fact prove feasible.

to meet all demands in the foreseeable future³ and while there are other significant markets for this coal, the alternative demands on the coal resources of Alberta will not greatly influence the cost or supply of coal to the electrical generation market. In order to justify the study of one segment of the coal industry in isolation from the remainder, it is necessary to describe what effects, if any, the supply and demand factors in the remainder of the industry have upon the supply and demand conditions in the segment producing for the electrical generation industry market.

(a) The 'Coking' Coal Market:

At present, the largest single market for coal produced in Alberta is that of the Japanese iron and steel industry. While Japan has substantial reserves of coal for most purposes, this coal is not of the 'coking' quality required in the chemical processes associated with the reduction of iron ore in blast furnaces. Seams of coking coal of the bituminous and semi-anthracite classifications underlie the Canmore and Crow's Nest Pass areas of Alberta and British Columbia. The coal mining companies in these areas have sought to capture part of the Japanese market for coking coals. In 1957, an inaugural shipment of one thousand tons of coking coal was sent to Japan and, in 1963, over 400 thousand tons

³ L.R. MacKay, "Coal Reserves in Canada", The Royal Commission on Coal, 1946 (Ottawa: 1946), Chapter 1 and Appendix A.

were exported to this market.⁴ Judging by this increase and recent export contracts for over one million tons per year, the coking coal producers in Alberta may continue to expand their sales to Japan. There are, however, political factors which must be considered. The Federal Government has provided a subvention (subsidy) on coal movement from mines in Alberta and British Columbia to Port Moody, British Columbia. This subvention reached a peak of \$4.43 per ton in 1959, but it has been reduced to \$2.73 per ton (to a maximum of 800,000 tons per year) for the period 1963 to 1965 inclusive.⁵ While subventions have been reduced and will be removed in the near future, coking coal producers have cut production costs through investments of some six million dollars (1958 to 1964)⁶ in mining equipment, surface plant, and research development. As a result, productivity has increased by 24 percent over this same period.⁷ Since Japan is the third largest iron and steel producer in the world, and since the rate of expansion of production is the highest in the world, the Japanese demand for

⁴ See Table 1, p. 14.

⁵ W.C. Whittaker, "The Interdependence of Coal and Bulk Carriers", Proceedings: Sixteenth Annual Dominion-Provincial Coal Research Conference, 1964, (Ottawa: 1964) p.22.

⁶ Ibid.

⁷ Ibid., p.23.

coking coal mined in Alberta will continue to provide markets for Alberta coal providing productivity is increased and transport costs are reduced relative to the costs of foreign competitors in the Japanese markets. The lack of statistical information, the complexity of international trade factors, the political considerations involved, particularly regarding subvention and freight rate aspects, and the possibility of new methods of bulk transportation are all factors which preclude a definitive study of this market for coal produced in Alberta in this thesis.

The cost per ton or per million Btu.'s (British thermal unit) of coking coal mined in the 'mountain' region of Alberta precludes its competition with oil, gas, or hydro used to produce electricity in Alberta. The market for coking coal is a function of its chemical properties and not its heat content, although the heat content is high relative to other classifications of coal. The electrical generation industry, on the other hand, requires a low cost, per heat unit, fuel. Since the technology of underground mining operations, involved in the mining of coking coal, is distinct from surface strip-mining operations, since the coking coal mine labour is organized under the United Mine Workers of America and the surface mine labour is not, and because the market for coking coal is distinct from the market for coal for use in thermal

electric plants, the supply and demand factors are not inter-related to any significant degree. A small amount of residual coal (slack) from underground coking coal mines may be sold to electrical generation plants but since the amount of slack, by itself, is insufficient to warrant construction of an electrical generation plant, transport costs preclude this slack from competing with coal strip-mined at a plant site.

b. Markets for Strip-Mined Coal:

While there are several underground mines which produce non-coking coal, these will be closed shortly or will continue to produce insignificant tonnages relative to total output.⁸ The output of strip-mine operations in Alberta, however, is increasing. There are five major strip-mining operations in Alberta at present. All of these mines have in common (relative to underground mines): high capital to labour ratios; high productivity per man; and low cost per heat unit. These factors have reduced costs per heat unit to make them competitive with other fuels and sources of energy in a number of markets.

⁸ See Appendix C, p. 96. The largest underground mine producing other than coking coal intends to shut down its underground mine in the near future. The five major strip mines are located at Wabamun, Forestburg, Battle River, Sheerness and Taber.

(i) Household and Industrial Space Heating:

Although this market has been shared with wood,⁹ natural gas, oil, and propane over the years, coal sales in this market have continued to decline at 12 to 15 percent per year in the 1960's.¹⁰ There are still rural areas in Alberta and Saskatchewan in which coal is used in household space heating but the prospects for increased sales in this market do not exist. Industrial space heating has been lost to alternative fuels and sources of energy to much the same degree.

Since strip-mining operations tend to be associated with decreasing costs over a wide range of operations, the decrease in demand in this market may adversely affect the cost of coal. Strip-mines, such as Forestburg where coal is sold to both the space heating and the electrical generation markets, will be faced with increasing costs

⁹ James V. Wessinger, "The Canadian Coal Industry", Report to the Chief of the Canadian Energy Board, October, 1966, pp. 36-38. "Despite the limited availability of fuelwood, (on the Prairies) as late as 1941 over 50 percent of the domestic fuel requirements were supplied by this source." and "The outstanding feature of the domestic heating market (in British Columbia) was the widespread use of fuelwood. In fact, 75% of all the domestic homes were supplied by this type of fuel (in the early 1940's)."

¹⁰ Interview with R.C. Sheldon, Pres., Weaver Coal Co. Ltd., Aug. 5, 1965.

Interview with Peter Cullimore, Pres., Forestburg Collieries Ltd., Aug. 19, 1965.

if the space heating market is not replaced by other markets. This increased cost of production could have an adverse effect on the demand for coal on the part of the electrical generation industry if other sources of electrical generation operate at constant or decreasing costs, relative to coal.

(ii) Industrial and Mining Heat Requirements:

While industrial space-heating is provided by sources of energy other than coal, the steam requirements of the pulp and paper industry and the mining operations of several potash mines are substantial.¹¹ These requirements are now being met with wood and natural gas in the case of pulp and paper plants and natural gas in the case of potash mines. Should transportation techniques such as unit or integral trains or solid carrying pipelines be developed and placed at the disposal of the coal industry, these markets may provide additional demand for the output of strip coal mines in Alberta. Assuming that economies of scale are available, the additional demand on the part of the pulp and paper industry and the potash industry will result in lower average and marginal costs. This condition would increase the demand for coal by the electrical generation industry as long as decreasing costs of coal (in absolute

¹¹ Interview with Peter Cullimore, Pres., Forestburg Collieries Ltd., Aug. 19, 1965.

terms and/or relative to other sources of electrical production) are evident.

(iii) Requirements of the Chemical Industry:

A similar circumstance of decreasing costs (economies of scale) may be realized if the metallurgic and chemical industries in Western Canada expand their levels of production. While there have been many suggestions that a coal based chemical industry could be developed in the future,¹² this industry is market-orientated and the Western Canadian market is not likely to expand sufficiently to warrant such investment in the near future. A fertilizer made from coal has been developed by the Alberta Research Council but Western Canadian soils are not deficient in the nutrients that it supplies. A foreign market for this fertilizer must be found before production on a large scale is feasible. The absence of markets, the abundant supply of carbons derived from oil, and the limited demand for coal that would arise even if a chemical or fertilizer industry was established, do not encourage an estimate of the possible additional demand for coal.

¹² N. Berkowitz, "Chemical Aspects", Proceedings: Ninth Annual Dominion-Provincial Coal Research Conference (Edmonton: 1957), pp. 79 ff.

Coal being strip-mined at Taber is presently being used in the metallurgic operations at Kimberley, British Columbia. In order to be suitable for the Consolidated Mining and Smelting Company iron plant, the Taber coal is first subjected to a low-heat carbonization process at a plant several miles north of Lethbridge. After it has passed through the low-heat carbonization process, this coal is competitive, in both price and quality sense, with coking coal mined in the underground mines in the Crow's Nest Pass area.¹³ The cost per ton and per Btu., at pit head, is thirty percent higher than the coal produced at other strip-mines and until economies of scale are realized, its markets will depend upon metallurgic demands for coal. Should metallurgic demands increase and the cost per million Btu. decrease as a result, this coal field may be able to compete with the four large strip-mines now largely dependent upon the electrical generation industry market.

B. The Electrical Generation Industry Demand for Alberta Coal

The coal mines that rely primarily on the electrical generation market are Wabamun (Whitewood) Mines, Forestburg Collieries, the Battle River Coal Company at Halkirk, and the Great Western Coal Company at Sheerness. The cost per million Btu.'s at these opera-

¹³ See Appendix D. p. 98.

tions are 9-9½ cents, 9½ cents, 13 cents and 12 cents respectively ¹⁴ and costs are expected to remain constant or decrease as production expands. If other markets for the output of these strip-mines are found, the cost per million Btu.'s should fall but if secondary markets are lost the costs should increase.¹⁵ Since there is a strong disposition on the part of the electrical generation industry to provide electrical power at rates which will remain constant or decline over the long run, coal appears to offer a source of electrical generation consistent with objectives of the industry.

While the decline in the demand for coal produced in Alberta during the post-war period is examined in considerable detail in Section A of Chapter II, Section B examines the growing interest in and the utilization of coal as a fuel in thermal electric generation. At the same time, alternative sources of electrical generation are considered.

In Chapter III, the market for electricity in Alberta is examined and, given trends in the costs involved in alternative

¹⁴ Interview with Peter Cullimore, Pres., Forestburg Collieries Ltd., Aug. 19, 1965.

Also see Appendix D, p. 98.

¹⁵ See Appendix E, p. 101.

electrical generation methods, the technological and cost factors affecting the decision to invest in coal-fired thermal electric generating units are presented.

In Chapter IV, the demand and supply projections of the electrical industry are presented. Given these projections, estimates of the derived demand for coal are made.

Since technological factors are subject to wide variance in the long run, estimates of the derived demand for coal by the electrical generation industry are made to the year 1980 only. The high and low estimates show wide variation since the trend is based on discrete additions to total capacity and a single decision to invest in one power source rather than an alternative will greatly influence the total consumption of a particular fuel or hydro resource.

CHAPTER II

THE ALBERTA COAL INDUSTRY, 1945 to 1965

As a percent of the total energy produced in and imported into the Canadian economy, Canadian coal production declined from 22.4 percent in 1945 to 7.0 percent in 1960.¹ This decline in the relative importance of coal occurred while the total energy produced in and imported into Canada doubled. In the Alberta segment of the Canadian coal industry, coal production decreased in absolute terms as well. Section A of this chapter examines the major reasons for the decrease in the demand for and the supply of coal produced in Alberta.

While the major markets for coal produced in Alberta were being lost to alternative sources of energy, the electrical generation industry and the Japanese iron and steel industry increased their interest in the potential use of Alberta coal. Section B of this chapter examines the growing interest and ultimately the increased demand for coal on the part of the electrical generation industry in Alberta. While the Japanese demand for coking coal produced in Alberta is a significant portion of total demand for Alberta coal, this demand will not be examined any further in this thesis.²

¹ See Appendix F, p. 102.

² See discussion on pp. 3 - 6.

Table 1

THE DISPOSITION OF ALBERTA COAL PRODUCTION.....1943 - 1963
(thousands of tons)

Year	Sold for consumption in					Sold to Others	Sold to Railroads	Total Sales	Total Output
	Alta.	B.C.	Sask.	Man.	Ont.	U.S.A.			
1943	1560	865	1456	627	1	414	2099	7071	7070
1944	1379	679	1229	531	10	259	2581	6697	7427
1945	1568	868	1242	542	278	163	2417	7099	7801
1946	1608	982	1449	659	348	137	39 - C	8137	8824
1947	1671	899	1475	583	163	91	42 - C	7434	8015
1948	1593	946	1413	625	203	84	201 - J	7378	8111
1949	1614	891	1233	629	188	46	3 - C	7618	8617
1950	1673	874	1367	587	313	106	44 - J	7227	8118
1951	1427	899	1322	493	182	80	1 - J	6891	7661
1952	1234	1021	1242	385	126	72		6148	7194
1953	1045	859	1035	275	73	47		4960	5917
1954	1065	891	996	292	85	33		4107	4859
1955	1080	933	893	294	91	33		3756	4457
1956	1021	806	871	305	75	46		3564	4330
1957	876	673	680	247	68	86	1 - J	2785	3155
1958	839	533	584	226	55	38	21 - J	2352	2520
1959	875	437	550	240	53	33	125 - J	2351	2550
1960	846	380	362	202	40	30	361 - J	2222	2404
1961	792	322	233	160	35	18	344 - J	1955	2028
1962	901	284	347	154	30	9	317 - J	2073	2087
1963	1073	262	343	131	29	6	411 - J	2273	2290

Notes: SB...Ship's bunkers, C...China, J... Japan, Total output minus total sales equals coal consumed at collieries or put to stock.

Source: Alberta, Department of Mines and Minerals, The Mines Division, Annual Report (Edmonton: annual).

A. The Declining Demand for Coal in the Space Heating and Railroad Markets.

a. The Space-Heating Market

Although Table 1 does not specifically classify coal sales in terms of sales to the space heating market, the bulk of the tonnage 'sold for consumption in Alberta, British Columbia, Saskatchewan, Manitoba, Ontario and the United States' has been used for household and industrial space heating. In the Alberta and Saskatchewan markets, however, the proportion of total sales which is consumed by the electrical generation industry has increased.³ As pointed out earlier,⁴ the demand for coal in the space-heating industry has decreased at an average of 12 to 15 percent per year since 1950. It is this trend rather than the decrease in the exact amounts of space heating coal consumption that is now examined.

Since natural gas was first commercially produced at Medicine Hat in 1904,⁵ industrial, commercial, and household heat requirements in Alberta have been served by natural gas as well as by coal, wood and oil. The discoveries of natural gas at Bow Island, Foremost, Turner Valley, and Viking-Kinsella and the subsequent

³ See Table 2, p.16.

⁴ See fn. p.7.

⁵ E.J. Hanson, Dynamic Decade (Toronto: 1958), p. 223.

Table 2

COAL USED IN CENTRAL ELECTRIC GENERATION
STATIONS IN ALBERTA.....1949 - 1964

Year	Total Tons of coal (000's)	Drumheller tons (000's)	Battle River tons (000's)	Wabamun tons (000's)
1949	404			
1950	303			
1951	184			
1952	131			
1953	170			
1954	124			
1955	157			
1956	80			
1957	134			
1958	163			
1959	187			
1960	205	58	147	
1961	223	69	154	
1962	352	68	144	140
1963	570	82	170	318
1964	1,094	52	228	814

Source: Dominion Bureau of Statistics, Central Electric Stations (Ottawa: annual). and
The Alberta Power Commission, Annual Report
(Edmonton: annual).

pipeline construction to the major centres of population in Alberta led to a substantial substitution of natural gas for coal and wood during the pre-1930 period. This trend has continued since that time.

"The sales of gas by the Canadian Western Company rose rapidly in the late 1930's and during the war years as the population of the centres served increased. The price of coal rose by one-fifth in 1939-46 and jumped to more than 50 percent above the prewar level in 1947. This spelled trouble for the coal industry in the urban centres served by gas. By 1946 the process of conversion to natural gas from coal was virtually completed in domestic and commercial establishments in Calgary, Edmonton and some small urban centres. Industrial users also swung over rapidly to natural gas".⁶

The continued discoveries of natural gas and oil during the late 1940's and 1950's led to more intense competition in the space heating market in Alberta. At the same time the network of pipelines expanded.

"There has been developed throughout Alberta (by 1954) an intricate distribution system for natural gas and propane reaching into communities both large and small".⁷

Even the rural areas, where coal had been a major space heating fuel, began to be captured by alternative fuels.

⁶ Ibid., p. 224.

⁷ The Dominion Coal Board, Annual Report, 1953-54 (Ottawa: 1954), p. 16.

"Propane, sold mainly to Alberta industries, small towns and farmers, rose from nothing in 1948 to almost one million barrels in 1956."⁸

The discovery, production and widening distribution of alternative hydro-carbon fuels in Alberta decreased the demand for Alberta coal in the space-heating market in Alberta first. The market for the alternative fuels widened with the permission given by the Alberta Conservation Board enabling gas and oil companies to 'export' these fuels to other provinces and the United States.

The West Coast Transmission pipeline which was begun in 1957 is designed to supply Vancouver, the 'Lower Mainland', interior British Columbia and the whole Peace River region with natural gas 'gathered' in the Peace River region. Surplus gas transmissions are consumed in the west coast States. The continued decline in sales of Alberta coal to British Columbia markets from 1956 to 1963 is shown in Table 1, page 14.

The Trans-Canada Pipe Line, amid much political and private debate, was constructed over the 1956-58 period. The easterly movement of natural gas from Alberta increased the consumption of natural gas in Manitoba (the Winnipeg and Central Gas Company and the Great Northern Gas Company) and in Ontario. The gradual

⁸ E.J. Hanson, Op. Cit., pp. 236-37.

decline in the consumption of Alberta coal in the space heating markets of these provinces in the post-1952 period was also due to imports of coal, oil, and natural gas from the United States.

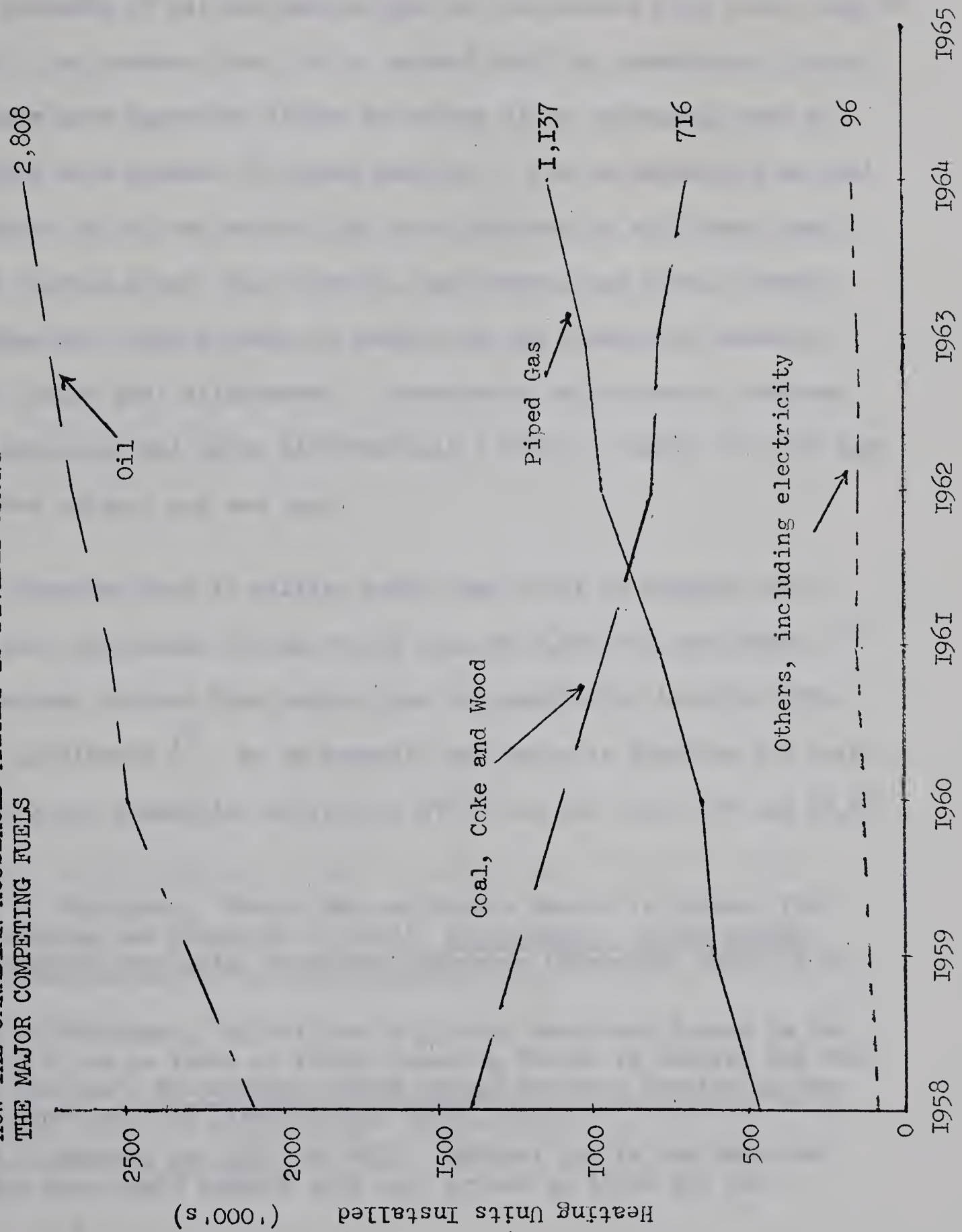
Since the early 1950's, there has been substantial gas and oil exploration and exploitation in Saskatchewan. Natural gas fields in the Kindersley and Medicine Hat areas (southwestern Saskatchewan area) have been developed and in 1957, the Saskatchewan Power Corporation was authorized by the Alberta Conservation Board to purchase natural gas from companies which had developed the Medicine Hat field in Alberta. The network of natural gas pipelines in Saskatchewan, although serving the larger centres, is not as extensive as that in Alberta.

The remaining space-heating market for Alberta coal consists of the rural areas of Alberta, Saskatchewan, Manitoba and British Columbia. This market, however, is declining. Figure 1 depicts the relative and absolute decline of coal in the household heating market in Canada. This trend is expected to continue for a number of reasons.

Oil, 'piped' gas and electricity are, relative to coal, coke and wood, 'convenient' sources of heat. The clean-burning feature (little soot or ash), clean and small storage space required (if any), and the adaptability to automatic control are

Figure I

HOW THE CANADIAN HOUSEHOLD MARKET IS DIVIDED AMONG THE MAJOR COMPETING FUELS



Source: The Financial Post, Mar. 20, 1965, p. 53.

all features of oil and natural gas not associated with coal, coke or wood. As incomes rise, it is assumed that the convenience factor becomes more important in the decisions of an individual when he decides on a furnace for space-heating. The inconvenience of coal relative to oil and natural gas also involves an additional cost. Fuel storage space, dust control, ash-removal and manual furnace feeding all involve costs to commercial and industrial concerns that 'piped gas' eliminates. Convenience and automatic features may outweigh fuel price differentials ⁹ where a choice is to be made between natural gas and coal.

Assuming that 17 million cubic feet (mcf) of natural gas is the heat equivalent of one ton of coal at 8,500 Btu. per pound, ¹⁰ it becomes evident that natural gas is competitive in price with coal in Alberta.¹¹ As an example, gas rates in Edmonton for residential and commercial users were \$7.70 for the first mcf and \$6.46

⁹ W.C. Whittaker, "What's New and What's Needed in Mining, Preparation and Transport of Coal", Proceedings: Ninth Annual Dominion-Provincial Research Conference (Edmonton: 1957), p.43.

¹⁰ W.C. Whittaker, "An Outline of Already Developed Trends in the U.S.A. as an Index of Future Canadian Trends in Natural Gas Distribution", Proceedings: Tenth Annual Dominion-Provincial Conference on Coal (Fredericton: 1958), p.29.

¹¹ E.J. Hanson, Op. Cit., p. 223. Natural gas in the Medicine Hat area could compete with coal priced at \$1.00 per ton.

for a second 17 mcf during the 1951-55 period.¹² At the same time, the average costs of coal at pithead for the three coal mining areas of the province were as follows: sub-bituminous, prairie region, \$4.82; sub-bituminous, foothills region, \$6.51; and bituminous, mountain region, \$6.07.¹³ Adding transportation costs, distribution costs and profits, the price advantage of coal, if any, is insufficient to overcome the 'inconvenience' of coal.

While strip-mines now produce coal at pit-head costs of less than \$4.00 per ton¹⁴ and semi-automatic coal furnaces have been designed to burn 'slack'¹⁵ (at even lower costs per ton), the rising incomes and increased leisure or convenience preference of the declining number of rural residents, warrants the conclusion that the space-heating market will become less significant in the future, insofar as coal producers are concerned.

¹² Public Utility Board for Alberta, Gas Guide (Edmonton: 1963), pp.8-9.

¹³ The Dominion Coal Board, Annual Report (Ottawa: annual). The figures in the text are averages for the years 1951 through 1955.

¹⁴ See Appendix D, p. 98.

¹⁵ N. Melnyk and W.A. Lang, "The 'Coal-Pak' and its Application to Alberta Coals", Proceedings: Tenth Annual Dominion-Provincial Conference on Coal (Fredericton: 1958).

b. The Railroad Market

The decline in the demand for coal in the railroad locomotive market was even more pronounced than in the space-heating market. The sales of Alberta coal to the railroads decreased from 2,443,000 tons in 1950 to 385,000 tons five years later.¹⁶ During the Depression and World War II, the railroads had foregone normal capital equipment replacement and, by 1950, the backlog of required replacements of locomotives included almost all the locomotives in Western Canada. The coal burning steam locomotives were the first to be replaced.

New diesel locomotives incorporated technological advances which made them relatively more efficient than new steam locomotives.¹⁷ The C.N.R. re-equipment program began in 1951 and, in 1953, the C.P.R. began to replace steam locomotives with diesel engines. Since 1958, the use of coal as a fuel in railroad locomotive power generation has been insignificant; this second 'traditional' market is lost forever.

While elaboration of the reasons for the railroad preference of diesel power to steam power is not necessary in order to examine thoroughly the prospects for the Alberta coal industry in the future, a brief review of these reasons will illustrate that the coal-steam

¹⁶ See Table 1, p. 14.

¹⁷ See Appendix G, p.103.

based technological make-up of our economy has been replaced, as illustrated in Appendix E, p. 101. Coal, and steam power associated with coal, has been displaced by other sources of energy simply on the basis of comparative costs if it is assumed that firms are maximizing profits. In consideration of locomotive power, the inconvenience of coal relative to diesel oil as a fuel is closely associated with relative costs. The maintenance of coal stockpiles and coal loading and unloading facilities at frequent intervals along the railroad lines is not only inconvenient but such facilities represent costs to the industry. Thus while the cost of the fuel itself may be lower for coal at the delivery point than for diesel fuel (per heat unit) and while the capital cost of diesel engines is higher than that of steam engines, the costs associated with the use of coal are greater (i.e. coal stockpiling, frequent stops to take on coal, and handling costs incurred in the feeding of coal to the burners, are all operational costs not to be found, or found to a lesser degree, in dieselized operations). In addition, diesel engines are maintained at lower costs and produce more power per locomotive unit than steam locomotives.

When added together, the loss of markets for the Alberta coal industry in both the space-heating and the railroad locomotive sub-markets caused the decline in total demand to be particularly severe; the discovery of large reserves of oil and natural gas

and the subsequent network of pipelines to most of the space-heating market roughly coincided with the dieselization policy of the railroad companies. While oil, natural gas, and diesel fuel became available at stable prices to these sub-markets, coal was becoming more expensive.¹⁸ The resistance of the coal industry to adopt technically advanced mining methods was partly to blame for higher costs.¹⁹ In the face of rapidly decreasing demand, the firms in the coal industry were reluctant to invest. In 1957, W.C. Whittaker noted that the decline in coal production appeared to follow a cumulative downward trend.

"Unfortunately we are in a vicious circle. It takes a good deal of courage under present conditions in both Western and Eastern Canada to make large capital investment necessary to modernize an old mine or to open a new one in the face of fast-disappearing markets. And yet, if the improvements necessary to reduce costs are not made, it will be difficult to remain in competition with lower cost operations and with other fuels."²⁰

¹⁸ The cost of coal at pit-head (underground mines) increased by approximately 50 percent from 1947 to 1958. The 'Mountain' region bituminous coal mining costs levelled out between 1957 and 1958 and fell thereafter (1947, \$4.31 per ton, 1958, \$6.68 per ton). The 'Prairie' and 'Foothills' underground mining costs rose from \$3.94 and \$4.50 per ton in 1947 to approximately \$6.82 per ton in 1958.

See The Dominion Coal Board, Annual Report (Ottawa: annual).

¹⁹ Interview with Bert Tait, Past Inspector, Alberta Department of Mines, Aug. 20, 1965.

²⁰ W.C. Whittaker, "What's New and What's Needed in Mining, Preparation and Transport of Coal", Proceedings: Ninth Dominion-Provincial Coal Research Conference (Edmonton: 1957), pp. 47-48.

The outlook for the coal industry in Alberta was not encouraging in the late 1950's. The widening preference for 'convenience' fuels in the space heating market and the technological advantages of diesel locomotives in the railroad market were the major demand factors which led to the decline of the coal industry in Alberta from 1945 to 1961. On the supply side, many underground mines were forced to close down as a result of sustained losses on operations. The underground mining sector which produced coking coal increased its efforts to capture part of the Japanese market in the post-1957 period. The strip-mining sector, which had steadily increased its share of the total coal market in the post-war period, continued to arouse the interest of the electrical generation industry in Alberta in the 1950's. This chapter now turns to a study of the growing interest of the electrical industry in the strip mining sector of the coal industry in Alberta.

B. Developments in the Demand for Coal by the Electrical Generation Industry*

While technological change was responsible for the improvement

* Throughout this section of Chapter 2 and in the following chapters, two terms will frequently be used; megawatt (MW) and Kilowatt-hour (KWH). Where the term 'capacity' is used, it will denote the rate of generation of electricity and this rate is expressed in megawatts. Where the term 'energy' is used it will refer to the quantity of electricity generated and this quantity is expressed in kilowatt hours. 'Load factor' will be used to denote the ratio of the energy generated from one unit to the capacity of that same unit to generate electricity, unless otherwise stated.

in the efficiency of diesel locomotives relative to coal-fired steam locomotives, technological developments during the post-1947 period improved the efficiency of thermal electric generation using coal as a fuel. Figure 2 on the following page shows that the average electrical generation of electricity (in kilowatt hours) per pound of coal (homogeneous) increased over the period 1940 to 1957. There is another factor, besides improved technical efficiency, which has improved the electrical output per unit of coal in the United States for the same period; growing demand for electricity warranted thermal-electric generation from optimum sized plants. In Alberta, the demand for electricity has been doubling every five to six years, and anticipating a continuance of this growth in demand, additions to capacity can be made in units of sufficient size to take advantage of the efficiency of large units vis-a-vis the smaller unit additions which were employed in investment programs prior to 1955.²¹ Because of the growing market for electricity in Alberta and because coal-fired electrical generation plants had been developed to a more technically efficient level, the electrical utility firms in Alberta began to investigate the possibility of an expansion of facilities involving thermal generation of electricity using coal as a fuel.

21

See Appendix A, p. 88.

Figure 2

AVERAGE COAL RATE OF THERMAL PLANTS IN U.S.A.



Source: Courtesy of M.M. Williams, Calgary Power Ltd.

The choice between alternative sources of electrical generation ultimately depends upon the present and projected competitive prices of these sources. While the known 'recoverable' coal resources of Alberta are enormous, most of this coal lies more than two hundred feet below the surface and, therefore, does not lend itself to highly efficient strip-mining techniques. There are several areas where coal seams lie less than one hundred feet below the surface and, since these seams can be strip-mined, the costs per Btu. are competitive with other fuel sources. It is the potential of these fields that the electrical generation industry began to examine in the early 1950's.

As the generation of electricity by nuclear means is still dependent upon Federal government assistance and is still deemed feasible only in extremely large capacity units, the electrical industry of Alberta devoted its investigations to alternative sources of electrical generation using resources available within the province. The resources involved are hydro-electric dam sites, oil, diesel fuel, natural gas and strip-mined coal.

Hydro-electric sites, at least in the southern section of the province where the growing demand for electricity is centered, are not abundant and the rivers of Alberta are characteristically inter-

mittent.²² This latter characteristic requires that dams and reservoirs be built in order to even the flow of water and thereby even the electrical output capacity. The capital cost of dams and the opportunity costs involved in flooding large areas of up-stream lands have become greater as the more desirable sites have been utilized. Calgary Power Ltd. has developed the more ideal sites for hydro-electric installations on the Bow River west of Calgary and, in order to expand hydro-electric generation capacity, it has been necessary to look to potential sites progressively more distant from the 'load centre' of electrical demand in Alberta.

There is a concern on the part of the Alberta government regarding water resources in Alberta. The supply of water for domestic, industrial, and agricultural consumption and problems such as pollution and assured long-run supply, are apparently of greater public concern than are problems related to the use of water resources for electrical generation. The use of Alberta water resources to gener-

22

For season and annual variability of flow of southern Alberta rivers see M.M. Williams, "Integration of Hydro and Thermal Power Resources in Alberta", Power Apparatus and Systems, October, 1957, pp. 4-5.

ate electricity has a low priority relative to these other considerations.²³

Thermal generation of electricity has become an economically realistic alternative to the hydraulic generation of electricity. This is particularly true where the fuel for thermal electric generation is near the provincial load centre (as an interconnected power grid system now exists in Alberta) or where the fuel can be transported to the load centre electrical generation plants at low costs.²⁴

The use of oil in thermal-electric generating plants has not received much attention from the electrical utility industry because of the cost of this fuel,²⁵ but natural gas has been considered and is

²³ While the Government of the Province of Alberta has financially assisted the construction of the Brazeau Dam, the Government's concern was to regulate the river flow variation in order to control pollution of the North Saskatchewan River below Edmonton during the low water period from October to April. The complete lower part of the dam was installed for this purpose in 1961-62 while the upper levels of the dam, which were to hold electrical generation equipment, were added later. See The Alberta Power Commission, Annual Report (Edmonton: 1962), p. 36 and The Alberta Power Commission, Annual Report, 1962 (Edmonton: 1963), p. 39.

²⁴ A further discussion of these factors follow in Chapter 3.

²⁵ "The cost of crude oil or its derivatives generally prohibits their use for electric power productions other than as a standby for natural gas or coal." M.M. Williams, Op. Cit., p. 1.

used as a fuel in a number of thermal plants. While internal combustion generation of electricity is used in the sparsely populated areas of northern Alberta, it is because local demand is limited and because long distance transmission of electricity is costly that the internal combustion small-scale plant is competitive in the northern part of the province. The competition between coal and natural gas in the southern area of the province continues to be the source of debate among those planning the future expansion of electrical generation capacity.

Coal has been used as a fuel in the generation of electricity in Alberta since 1910.²⁶ It had been, over the years prior to 1955, a practice of the electrical generation industry to utilize much of the coal-fired generating capacity as a stand-by electrical source to meet 'peak' demand (load) requirements and, as a result, coal tonnages used during various years registered sizeable variations.²⁷ As hydro and non-coal thermal capacity increased from year to year, coal-fired thermal generation of electricity decreased as the new non-coal plants provided capacity to meet

²⁶ The Alberta Power Commission, Annual Report, 1951, (Edmonton: 1952), p. 12.

²⁷ See Table 2, p. 16.

peak electrical demands also. During the early 1950's gas-fired thermal generation of electricity in new generating units began to replace the older coal-fired generators in meeting both peak demands and in providing 'base' load electricity. As an example, the City of Medicine Hat added gas-fired units to its electrical generation plants in 1953²⁸ and withdrew its coal-fired units from production in 1954.²⁹

By the mid-1950's, the Drumheller plant of Canadian Utilities and the Sentinel plant of East Kootenay Power were the main consumers of coal for the generation of electricity. While a decrease in the sales of coal to the electrical generation industry in Alberta is evident in the years 1949 to 1955, as shown in Table 2 on page 16, the two privately owned giants of the Alberta electrical-generation industry³⁰ began to investigate the feasibility of using coal as a fuel in thermal electric generation to meet the 'base' load in Alberta. The publicly-owned City of Edmonton

²⁸ See Appendix A, p. 88, for chronological break-down of the installation of new generating units.

²⁹ Alberta Power Commission, Annual Report, 1951 (Edmonton: 1952), p. 15.

³⁰ See Appendix A, p. 88. Although the City of Edmonton electrical generation system is a larger producer than Canadian Utilities, Ltd., Calgary Power Ltd. and Canadian Utilities are both privately owned.

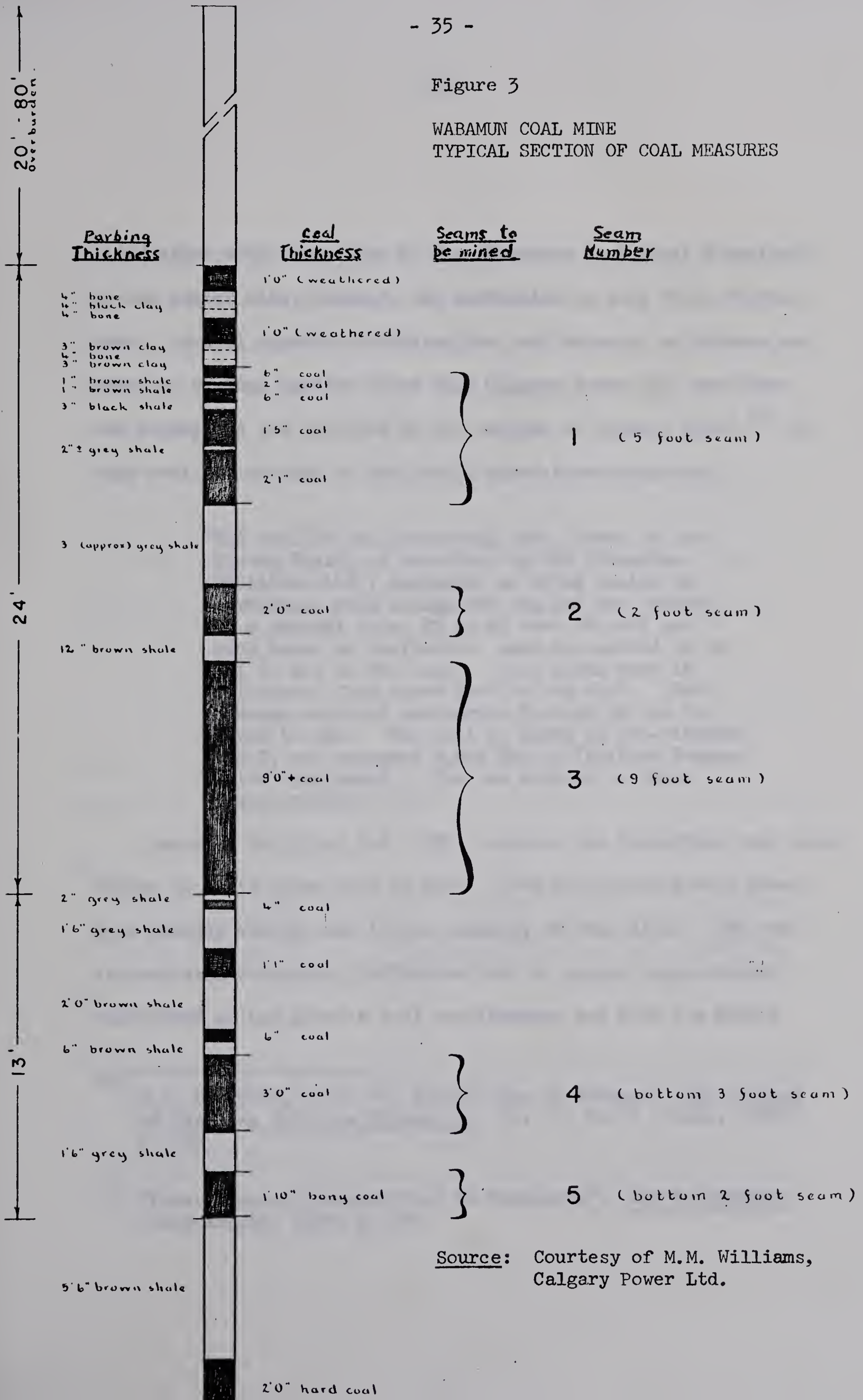
electrical generation system also began to survey the feasibility of a coal-fired thermal unit at Genesee. The two private firms have translated their investigations into investment programs at their Wabamun (Calgary Power) and Battle River-Forestburg (Canadian Utilities) plant sites; the City of Edmonton appears to have settled on a natural gas thermal plant in Edmonton instead of a coal-fired plant at the Genesee site. With due respect to the authorities responsible for the feasibility studies into the Genesee and Ardley³¹ proposed projects, this thesis will examine only those developments which have in fact led to a greatly increased demand for coal. This approach has been followed in order that actual performance of coal-fired thermal units could be examined. Since both Calgary Power and Canadian Utilities are expanding their present coal-fired generation facilities, it is assumed that electricity generated using coal as a base fuel is competitive with electricity generated by other means. A further examination of the generating operation at Wabamun and Forestburg-Battle River is thus warranted.

The geological profile, shown in Figure 3 on page 35, of the Wabamun area is roughly applicable to the Battle River-Forestburg

³¹ See Appendix H, p.104. This 'report' outlines some of the information which was gathered to promote the Ardley proposal. Note that heat value per pound (6800 Btu.'s) is less than the average at Wabamun (8,000 Btu.'s per pound) and Forestburg-Battle River (8,500 Btu.'s per pound).

Figure 3

WABAMUN COAL MINE
TYPICAL SECTION OF COAL MEASURES



Source: Courtesy of M.M. Williams,
Calgary Power Ltd.

field since both fields lie in the 'Edmonton Geological Formation'. At the latter site, however, the overburden is only 35 to 40 feet deep. Gravel deposits overlying the coal deposits at Wabamun are owned by various parties other than Calgary Power Ltd. and these are stockpiled and levelled at the expense of Calgary Power.³² No such cost is involved at the Battle River-Forestburg site.

"The coal in the Forestburg area, known as the Castor Field, is described by CUL (Canadian Utilities Ltd.) engineers as being easily recoverable, with a high Btu and low ash content. As a general rule, 35 to 40 feet of soil and rock known as overburden, must be removed in order to get to the coal. Coal seams vary in thickness, from three feet to ten feet. The average ratio of overburden to coal is six or seven to one. The coal is known as sub-bituminous C, and averages 8,500 Btu.'s (British Thermal Units) per pound.³³ The ash content is about seven percent."

Canadian Utilities Ltd. (CUL) selected the Forestburg area coal fields as their plant site in 1954. Two strip-mining coal firms were already mining coal in the vicinity of this site. CUL contracted with Forestburg Collieries Ltd. to supply approximately two-thirds of the plant's coal requirements and with the Battle

³² G.H. Thompson, "Coal vs. Natural Gas at Wabamun", The Journal of Canadian Petroleum Technology, Vol. 1, No. 4, Winter, 1962, p. 180.

³³ "Power Company Converts Coal to Kilowatts", The Transmitter, July-August, 1965, p. 16.

River Coal Co. Ltd. at Halkirk to supply the remaining one-third.³⁴ CUL thus avoided capital expenditures on coal mining equipment but since large amounts of cooling water are required in thermal plant operation, the company undertook the construction of a dam on the Battle River to provide a condensation pond. The CUL plant is the largest single consumer of coal produced by both Forestburg Collieries and the Battle River Coal Company³⁵ and competition between the two companies plus long-term contracts with low price escalation clauses assure relatively stable prices to meet long-term coal requirements.³⁶

There is no foreseeable shortage in the supply of recoverable coal in the vicinity of the CUL plant³⁷ and since Forestburg Collieries invested in the largest coal stripping machine in Canada

³⁴ "Forestburg Mine Operations Rates With the Most Modern in the World", SRM News, Vol. 5, No. 4, April, 1963, p. . Also see Appendix D, p. 98, Par. No. 3, for the share of The Battle River Coal Co. Ltd. in the Canadian Utilities Ltd. electrical generation operation at Battle River.

³⁵ SRM News, Op. Cit.

³⁶ Interview with Peter Cullimore, Pres., Forestburg Collieries Ltd., Aug. 19, 1965. Mr. Cullimore estimates pit-head cost of coal at Forestburg Collieries at $8\frac{1}{2}$ to 9 cents per million Btu.

³⁷ The Transmitter, Op. Cit. "Officials estimate recoverable coal reserves within five miles of the plant to be in excess of 100 million tons. This figure doubles if the radius is extended another ten or fifteen miles."

in 1962 (Bucyrus-Erie shovel with a 36 cubic yard bucket) coal costs are expected to decrease.³⁸ The Battle River Coal Company also uses large-scale mining methods.

"Coal used in the Canadian Utilities Battle River Station is purchased under contract and strip-mined by two coal companies: Forestburg Collieries Limited and the Battle River Coal Company Limited. Both companies use large shovels and drag-lines operated by electricity from the plant. Buckets on the earth-moving equipment can scoop up and remove anywhere from 20 to 36 cubic yards in one 'bite'. After the coal is mined it is transported to the power plant by haulers weighing nearly 100 tons when loaded."³⁹

The experience with coal-fired generation of electricity must have been favourable since CUL added a second 35 MW unit in 1964 to the 35 MW unit which had been in operation since 1956. The consumption of coal by both of the units in 1964 was roughly one-quarter of a million tons. A third unit, 150 MW, is now being added to the plant. This will bring the total coal demand at this one plant up to approximately 750,000 tons per year in 1969 when the 150 MW unit becomes operational.⁴⁰ The cost to CUL of this

38

See Appendix E, p. 101.

39

The Transmitter, Op. Cit.

40

Ibid. Also see Appendix D, p. 98, for a similar estimate by the Alberta Coal Company.

fuel has been estimated at somewhere between $8\frac{1}{2}$ cents per million Btu.'s to 13 cents per million Btu.'s.⁴¹ Plans for further expansion of this plant shall be discussed later.⁴²

Except for thermal electric projects sponsored jointly by Calgary Power Ltd. and municipal utility companies,⁴³ Calgary Power generated electricity wholly from its hydro-electric plants on the Bow River system west of Calgary until 1956. In addition to the limitations to the utilization of hydro resources for electrical generation in Alberta that were mentioned earlier, the President of Calgary Power commented upon the possible hydraulic resources available to the company in 1962.

"The North Saskatchewan River offered a limited solution, but at a fairly high cost. The Brazeau River offered attractive peaking possibilities, but was limited in energy or KWH. The Athabaska River offered economical and well

⁴¹

Interview with Peter Cullimore, Pres., Forestburg Collieries Ltd., Aug. 19, 1965. Mr. Cullimore estimates pit-head cost of coal at Forestburg Collieries at $8\frac{1}{2}$ to 9 cents per million Btu.

Interview with W. Sterling, Engineer Canadian Utilities Ltd., Aug. 10, 1965. Mr. Sterling estimates the cost of coal from Forestburg Collieries at $9\frac{1}{2}$ cents per million Btu.

See Appendix D. p. 98. Para. No. 5 estimates Battle River Coal Co. Ltd. produces coal at 13 cents per million Btu.

⁴²

See Chapter 4.

⁴³

For a further discussion regarding Calgary Power Ltd. purchases of off-peak power from other producers see G.H.Thompson, Op. Cit. pp. 180-181.

balanced possibilities for development, but was too large and costly an undertaking for the Company at that stage in its load growth (1955)".⁴⁴

The growth in the demand for electricity in Alberta and the lack of economical hydro-electric sites in the southern half of the province forced Calgary Power to examine the feasibility of thermal generation of electricity. This investigation into the use of coal in thermal-electric generation units was begun in 1950 on the assumption that natural gas would in the long-run become too expensive a fuel.

"Natural gas is, however, an ideal fuel for house heating and can be transported long distances economically. It will therefore, in a comparatively few years, be absorbed in the export market to the limit set by the Province. At the same time the price of natural gas in Alberta will inevitably rise above the low level enjoyed today (1957, 10½ cents per million Btu.). When this time arrives, the interest of the Province will best be served by using, wherever practicable, local coal for producing power. In contrast to natural gas, coal cannot be economically transported long distances and its price will remain relatively stable over a long period. These factors make coal particularly well suited to supplying the long-term power requirements of Alberta".⁴⁵

⁴⁴ Ibid., p. 181.

⁴⁵ M.M. Williams, Op. Cit., pp. 1-2.

The growth of the demand for electricity in Alberta was an essential element in providing an economical basis for thermal electric plant investment; it was felt that the 66 MW (net) capacity plant was the minimum size at which economies of scale could be obtained.

"A thermal plant had been under consideration for some years and the load had now (1955) grown to the point where the Company could justify the installation of a 66,000 KW (net) steam turbo generator unit, a size large enough to take advantage of low capital and operating costs".⁴⁶

The Wabamun coal-fired electrical generation plant was designed to burn coal from the start (1956) but while the investment program was still sufficiently flexible to adapt to changes in the relative costs of coal and natural gas, Calgary Power was offered sufficient natural gas, at $10\frac{1}{2}$ cents per million Btu.'s⁴⁷ to meet growing demands for electricity for a few years. This temporary price advantage of natural gas vis-a-vis coal enabled Calgary Power to complete its investment in plant prior to developing the coal mining operation. Calgary Power had committed

⁴⁶

G.H. Thompson, Op. Cit. p. 181.

⁴⁷

Ibid.

itself to the purchase of coal rights and coal mining capital equipment ⁴⁸ and the plant expansion continued to be designed to burn coal despite the fact that the second 66 MW (net) unit installed in 1958 also burned natural gas.

"The initial gas supply, some 30 billion MCF (million cubic feet) at $10\frac{1}{2}$ cents per million Btu.'s was exhausted in 1961 and the additional gas to carry the plant through the present period (1962) is costing 15¢ per million Btu.'s".⁴⁹

In 1962, the 150 MW (net) unit was installed and by this time the 'captive' coal mine was in operation. This unit burned coal only and was placed on full load (capacity) immediately. The average cost per million Btu.'s is expected to fall as further units are added or converted to coal.

"The heavy initial investment in coal lands, surface rights, haul roads, highway changes, mine development, stripping, hauling, treating, conveying and pulverizing equipment, etc. will result in a cost of approximately 17 cents per million Btu.'s for the initial 780,000 tons per year required by the No. 3 Wabamun unit of 150,000 KW --- having already incurred the heavy initial investment for the purchase and development of the coal mine, the cost per million Btu.'s will drop rapidly

48

Ibid. p. 182.

49

Ibid. p. 181.

as additional coal-fired units are added. For instance, the incremental cost for the 360,000 tons of coal required to service each of the existing gas-fired 66,000 KW units (if converted and operated at high L.F.) will be less than 6 cents per million Btu.'s. With the fourth generating unit of 225,000 KW installed in 1967, the overall cost of coal fuel will be reduced from the 17 cents, mentioned earlier, to 9 cents per million Btu.'s".⁵⁰

In 1963, a new contract for quantities of natural gas at $12\frac{1}{2}$ cents per million Btu.'s was signed by Calgary Power ⁵¹ and, at this price, the company has continued to operate its two 66 MW (net) units using natural gas. While the cost of natural gas has increased from $10\frac{1}{2}$ cents per million Btu.'s in 1956 to $12\frac{1}{2}$ cents (19% increase) in 1963, there has been no tendency for coal costs to rise. Until such time as the cost advantage of coal, relative to natural gas, becomes sufficient to cover the capital costs associated with converting from natural gas to coal burning facilities it is likely that both 66 MW units continue to use natural gas.

The comparative costs of various fuels which may be used in thermal generation of electricity are not the only factors con-

50

Ibid, p. 182.

51

Ibid.

sidered when an electrical utility company examines alternative plant possibilities. In Chapter 3, some of the theoretical factors considered by electrical utility companies, in regard to the feasibility of investment in coal-fired thermal electric generation units, will be examined. The actions taken by Calgary Power at their Wabamun project and by Canadian Utilities at their Battle River project will be used as practical examples of the application of these theoretical considerations.

It would appear that the demand for coal on the part of the electrical generation industry will continue to increase in the future as the cost of natural gas continues to rise relative to the cost of equivalent heat provided by coal. In thermal plants which are operated at a high load factor in order to meet base load, the variable (largely fuel) costs are crucial in the long run as plant and unit life is considered to be approximately 40 years. Coal-fired units are initially higher in cost than gas-fired units.⁵² Because the variable costs are relatively more important than capital and fixed costs on base load plants in the long run, Calgary Power has purchased the mineral rights in the Wabamun field and has undertaken to finance the purchase of heavy coal mining equipment.

⁵²

C.E. Baltzer, Thermal-Electric Power in Canada with Particular Reference to the Regional Fuel Requirements of Thermal Generating Facilities Operated by the Thermal Electric Utility Industry, (Ottawa: 1960).

"Ownership by the Company of the coal mine and of the heavy equipment, in conjunction with the type of operating agreement entered into with Alberta Coal Ltd., should assure fairly stable fuel costs throughout the life of a 500,000 KW thermal plant". 53

It is the tendency of coal costs to decline, over the life of a thermal unit, in a number of areas of Alberta where strip-mining is possible that leads to optimism regarding the magnitude of the demand for coal by the electrical generation industry in the future.

CHAPTER III

MAJOR FACTORS AFFECTING THE DECISION to INVEST in COAL-FIRED THERMAL ELECTRIC GENERATING UNITS - THE ALBERTA EXAMPLE:

In the design of a particular new plant or an addition to an existing plant, consideration must be given to the capacity and efficiency of the established system. In the Alberta case, the established system consists of a number of generating plants interconnected by the 'Provincial Grid'. The previously established electrical generating plants use a variety of power sources (hydro, coal, natural gas and diesel oil) and each plant generates electricity at different marginal and average costs. Since there is an inter connection of most generating plants in the province, most new plants and additions to existing plants must be economically justified on the basis of their prospective role in the system as a whole.

The demand on the entire electrical generating industry, and the anticipated growth in this demand, affects the investment decisions regarding each plant. Given the capacity of the existing system and the anticipated energy demand on the system, the size of the additional plant or unit, relative to the capacity of the system as a whole, must be consistent with the capacity which it is necessary to hold in reserve for emergency conditions and

for peak electrical demands. If, for instance, the demand on an entire system requires a capacity of 1200 MW, and if it is felt that a 25% emergency reserve capacity at the peak load is desirable, no single plant or unit would be allowed to provide more than 25 percent of the entire system's capacity, i.e. 300 MW. It is for this reason that large-scale thermal generating units are a recent addition to the Alberta electrical generation scene.¹ Figure 4 on page 48, shows that the relative capital cost, per unit capacity, of units of various sizes favours 'complete stations'² of 500 MW's. Unit 'extensions' to one plant are subject to relatively lower capital costs up to an 825 MW unit. The limitations to plant size, consistent with decreasing costs (per unit capacity) are technological limitations

1

J.G. MacGregor, "Coal for Electricity in Alberta", Proceedings: Sixteenth Annual Dominion-Provincial Conference on Coal. (Edmonton, 1964), p. 2.

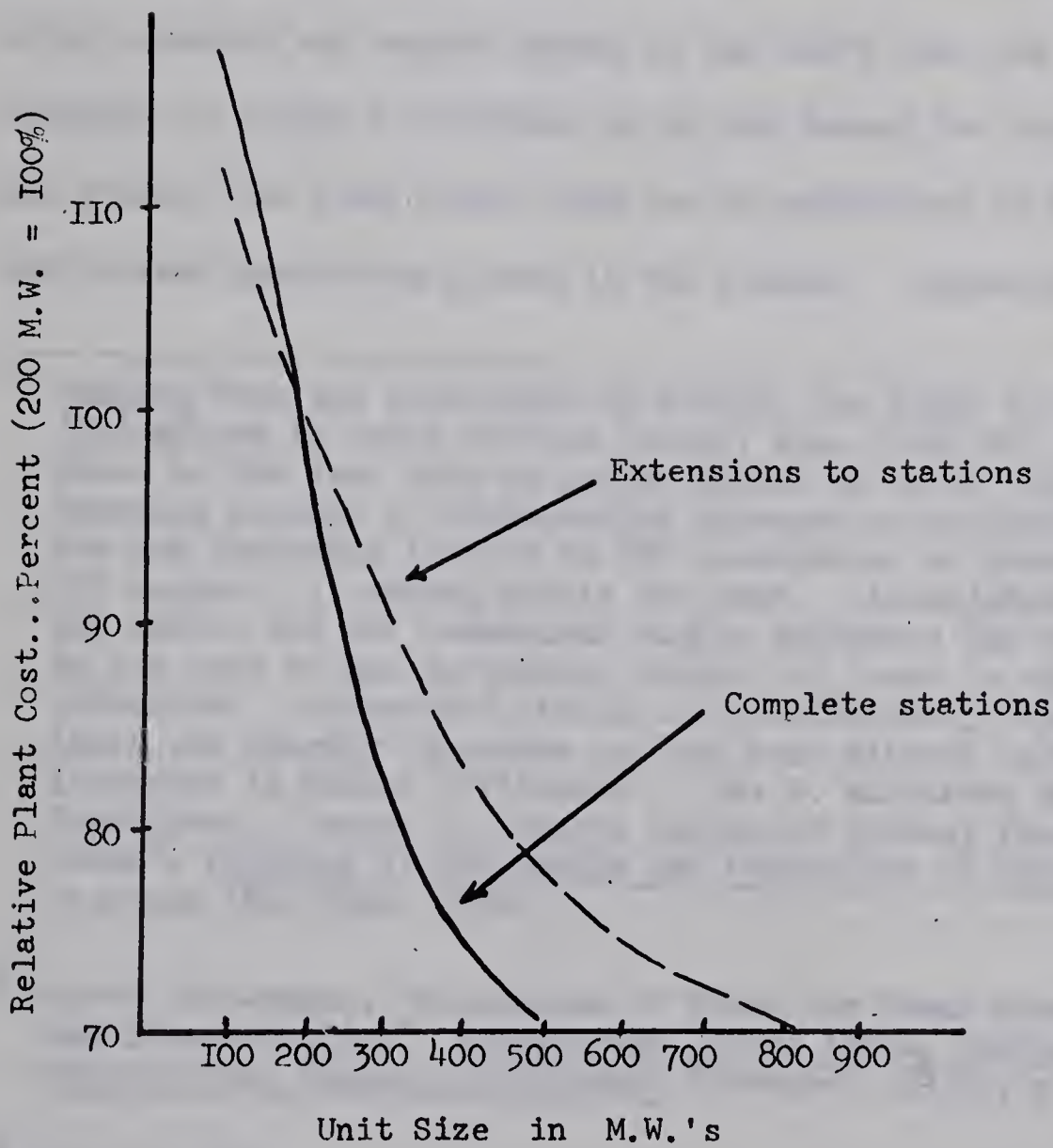
"Our capacity at the moment is about 1200 MW (in Alberta) -- Our load however, is of such a size that we can now talk in terms of units of 300 MW. Such units make it possible to open up a large scale mine and to operate it at a high load factor and hence, to produce coal at a low costs per ton".

2

In this instance 'complete stations' refers to a station with one boiler unit.

Figure 4

VARIATION OF PLANT COST WITH UNIT SIZE



Source: Courtesy of Wilson Sterling, Canadian Utilities Ltd.

that exist at this time.³

Appendix I illustrates that not only capital costs decrease with increasing generating-unit size but average fuel costs and, in particular, labour costs decrease significantly as the unit size increases to the technological limit (assuming constant fuel cost per heat unit).⁴ While it is true that additions to generating capacity may exceed demand in the short run, the closer the capacity to supply electricity is to the demand for electricity, the greater the load factor that can be maintained on the added and present generating plants in the system. Appendix J⁵ shows

³ Judging from the experience in Europe, the limit to unit size (500 MW) and to total station (plant) size (2400 MW) is determined by the fact that on larger plants or units capital costs increase without a corresponding increase in efficiency. Boilers are presently limited to 180 atmospheres of pressure with 535 degree C if normal steels are used. Associated with larger units, and the consequent higher pressures and temperatures, is the need to use austenitic steels, at least in valve construction. Austenitic steels are prohibitively expensive and their use sharply increases capital cost without corresponding increases in boiler efficiency. See S. Malokanov and A. Ivantitsky, "Trends in General Design of Thermal Power Stations", Problems in the Design and Operations in Thermal Power Stations (New York, 1964).

⁴ David Cass-Beggs, "Assessment of Costs for Power Generation and Transportation", Proceedings: Ninth Annual Dominion-Provincial Coal Research Conference (Edmonton, 1957), p. 109.

⁵ Ibid., p. 110.

the effect of load factor on generation costs for plants with various capacities (MW). (Note: Appendices I and J assume 25 percent capacity held in reserve and 'load factor' in these instances refers to the percentage of average load to 75 percent of the total capacity of the plant. If no reserve capacity is allowed for, the plant could operate at even lower costs. In the Alberta interconnected utility system, there are plants operating at full capacity (i.e. no reserve capacity). Reserve capacity to provide for peak loads (demand) and emergency requirements is provided by hydro-electric plants in the Calgary Power system).

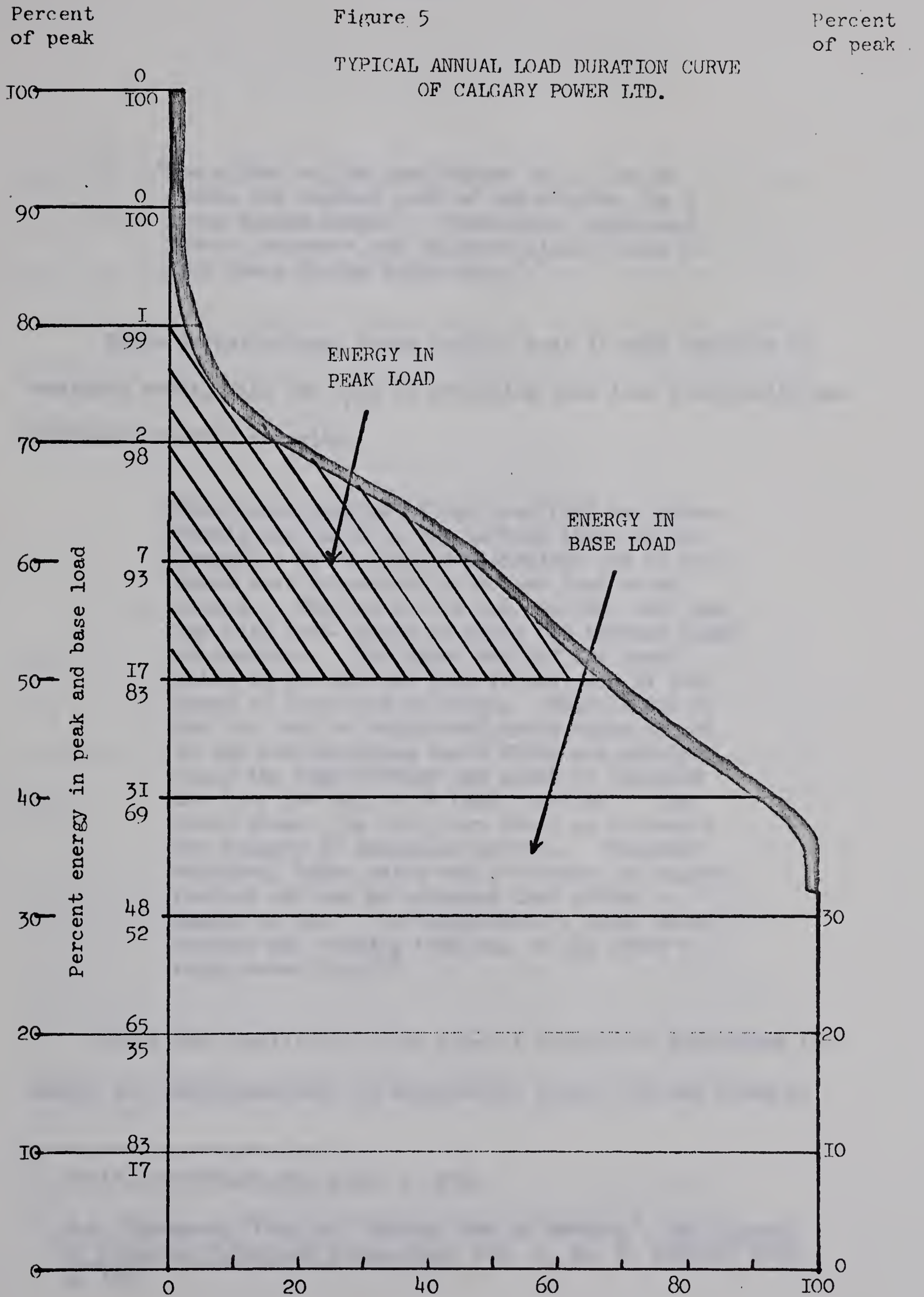
Figure 5 on page 51 shows the typical annual 'load duration curve' of Calgary Power Ltd.⁶ The base load is that part of the total demand which prevails 24 hours per day, 365 days per year, while the peak load includes daily and seasonal 'peak' demands such as early evening and the pre-Christmas season respectively. Because fuel costs are the most important element of total costs in base load plants and because Calgary Power Ltd. expects the lowest long-run fuel costs to be associated with coal rather than natural gas, the Wabamun coal-burning unit is designed to operate as close to 100 percent capacity as possible without an emergency reserve being included.

6

M.M. Williams, "Integration of Hydro and Thermal Power Resources in Alberta", Power Apparatus and Systems, October, 1957 issue, p. 1.

Figure 5

TYPICAL ANNUAL LOAD DURATION CURVE
OF CALGARY POWER LTD.



"The effect of low load factor is --- to increase the capital cost of the station for a given energy output. Conversely, high load factor increases the relative significance of fuel costs in the total cost."⁷

Hydro installations, where capital cost is high relative to variable costs, fill the role of providing peak load electricity and emergency reserve capacity.

"This lower portion of the load (but not necessarily the half) is the portion that, in the Company's hydro-steam combination, can be produced most economically by base load steam plants. This is due to the low fuel cost and the high load factor at which the thermal plant is operated. The upper half of the load, which is at very low load factor, can be produced at less cost by hydro. This is due to the low cost of additional hydro capacity and to the low operating costs which are practically the same whether the plant is operated one hour per day or 24 hours per day. The hydro plants, as well, are ideal as a reserve for standby or emergency service. Whenever required, hydro units can be started by remote control and can be carrying load within a minute or two. By comparison, a large steam turbine may require from one to six hours to bring under load".⁸

Since the facilities of the Alberta electrical generation industry are interconnected, an opportunity exists for all firms to

⁷ David Cass-Beggs, Op. Cit., p. 101.

⁸ G.H. Thompson, "Coal vs. Natural Gas at Wabamun", The Journal of Canadian Petroleum Technology, Vol. 1, No. 4, Winter, 1962, p. 182.

plan base load capacity utilizing the cheapest available fuel and for all firms to depend on the hydro facilities of Calgary Power to meet peak demand and to provide emergency reserve capacity. The economies derived thereby, however, must be large enough to cover the cost of interconnection and EHV (Extremely High Voltage) transmission loss of electricity.⁹

"It should also be noted that scale of operation is involved. It is impractical to consider EHV transmission unless the magnitude of the load justifies the large capital expenditures which would be necessary".¹⁰

The fact remains that a high voltage interconnection of the Alberta electrical system does exist and that the opportunities to rely on large scale plants to provide base load electricity are now available due to the absolute size of the entire Alberta electrical market.

9

This concept is the basis of arguments for a 'National Grid'; produce electricity where the costs are lowest and transmit it to areas where the cost would be higher. Here again, the capital cost of transmission facilities and the electricity lost in transmission must not offset the gains from relying on the lowest cost producing area. For further discussion regarding the 'National Grid' see

David Cass-Beggs, "Coal and the National Grid", Proceedings: Fifteenth Dominion-Provincial Conference on Coal (Ottawa: 1963), pp. 91-111.

10

R.E. Tweeddale, "Pitheads vs. Load Centres as Locations for Power Plants", Proceedings: Fifteenth Dominion-Provincial Conference on Coal (Ottawa: 1963), p. 113.

"---the process of interconnection provides the opportunity for locating plants at the most economical positions for the cheapest fuel and the greatest load". 11

Once an electrical utility company has ascertained the appropriate plant size considering the system as a whole and once the load factor at which the additional unit or plant will be operated is determined bearing in mind peaking, emergency, and base load considerations, the 'load centre' of the system determines the relative advantages of plant location. Because desirable hydro sites are long distances from the provincial load centre, and even from isolated centres of heavy demand, utilization of these sites has been postponed in favour of thermal plants nearer the provincial and/or local load centres. Also, because high electrical transmission costs are involved, Northland Utilities (a subsidiary of Canadian Utilities Ltd.) maintains relatively small internal combustion electrical generators in north-western Alberta rather than transmit electricity into that area from more efficient generating plants in central Alberta; the cost of transmission is compounded by the low load factor that would be involved.

11

David Cass-Beggs, "Assessment of Costs for Power Generation and Transportation", Proceedings: Ninth Annual Dominion-Provincial Coal Research Conference (Edmonton: 1957), p. 102.

Assuming that hydro-generated electricity will provide peak and emergency demands in Alberta for a number of years to come, the choice of base load fuel and plant location involves considerations of the cost of transporting the fuel vis-a-vis electricity to the load centre (provincial or local).

"For maximum reliability and economy, a large efficient thermal plant, supplying a high percentage of the energy requirements to a complex interconnected load system, should not be located on a long radical transmission line feeding into the system. It should preferably be on a grid system of transmission lines passing through the plant location, making possible a flow of power in more than one direction. The ideal, of course, would be to have all three conditions for optimum location of a large efficient thermal generating station; that is an adequate supply of cooling water adjacent to a coal mining area of considerable proportions and on an interconnected grid system".¹²

In Alberta, the 'ideal' conditions are met in the case of existing coal-fired thermal electrical generation plants. Lake Wabamun provides the Wabamun plant with an adequate 'cooling pond' and the Battle River plant is provided with an artificial 'cooling pond' on the Battle River. The coal deposits at both sites are sufficient to provide constant or decreasing fuel costs over the life of the plants (35 to 40 years) at least.

12

R.E. Tweeddale, Op. Cit., p. 118.

Appendix K depicts the interconnected Alberta 'power grid'. As the provincial load centre is just south of Edmonton, transport (transmission) costs to the load centre are less than one-half mill per KWH from either coal-fired plant. The concept of 'load centre' varies between firms and the industry as a whole. It is to be expected that the individual firm, in a multi-firm industry, will attempt to centre its electrical generation operation as close as possible to its own market demand 'centre'. This orientation is particularly true where no interconnection exists and thus the pre-established system will continue to show firm, rather than industry, location orientation following the establishment of a grid system. In the case of the City of Edmonton electrical generation firm, the City represents both the load centre and entire market.

In order to compare the relative costs of transmitting electricity or moving fuel to a given load centre, the costs involved must be converted to a common denominator. The common base measurement used is the cost per KWH for electricity delivered at or generated at the given load centre. In the case of electrical transmission, the cost of HV lines, the electrical loss factor over the distance from plant to load centre, and the load factor on the transmission line itself are included in the total costs at the load centre. Where fuel is moved from the mine or well to the load centre, the transportation cost as well as the efficiency of

conversion of fuel to electricity at the load centre electrical generation plant must be considered. The cost of transporting coal by rail in Western Canada is a function of distance and direction.¹³ 'Unit' or 'integral' trains, if employed to transport coal, will reduce the average transport cost per car load of coal by minimizing switching operations and reducing the 'turn around' time on each car.

Appendices M and N show the costs of power transmission and coal transportation in Western Canada at 50 percent load factor (Appendix M) and 90 percent load factor (Appendix N). At high (90 percent) load factor, it is always more economical to transmit electricity rather than move coal by rail, assuming that the electricity would be generated by identically efficient coal-burning plants in either location. Trucking coal is less costly than shipping coal by rail if the transport distance is less than 200 miles, and pipelining coal (assuming a water slurry) is less costly than moving coal by rail where distances are less than 40 miles. It is interesting to note that pipelines are competitive with HV transmission lines where 200 MW generating units are considered and where the distance involved in transport-transmission

13

See Appendix L, p. 112 regarding railroad costs for coal movement in various directions.

is less than 200 miles.¹⁴ Assuming the efficiency of conversion of gas or coal to electrical energy is taken to be 12,500 Btu. per KWH, Table 3 below outlines transportation rates (mills per KWH per 100 miles), for natural gas and coal. Assuming a 138 kv., wood pole construction electrical transmission line operating with a capacity of 60 MW and a 10 per cent transmission loss, Table 3 illustrates the relative costs of transporting electricity and fuels to a load centre generation plant. Various load factors are considered.

Table 3 **Comparative Transport-Transmission Costs**
(mills per KWH per 100 miles)

	90% L.F.	75% L.F.	50% L.F.	15% L.F.
Gas	0.20	0.22	0.28	-
Coal	1.25	1.25	1.25	-
Electricity	0.39	0.59	0.59	1.43

Source: David Cass-Beggs, "Assessment of Cost for Power Generation and Transportation", Proceedings: Ninth Annual Dominion-Provincial Coal Research Conference (Edmonton: 1957), p. 106

14

Dr. N. Berkowitz of the Research Council of Alberta has written a number of articles regarding the pipeline transmission of solids, including coal, suspended in solution or capsules, e.g. Pipeline Transmission of Coal and Other Materials in Association with Oil, 1964, available at the Research Council of Alberta library. In fact, a coal pipeline, 108 miles in length and 10 inches in diameter is the transport medium for coal mined at Cadiz, Ohio and burned at the East Lake Station of the Cleveland Electrical Illuminating Company.

Also see C. Moreland, "Pipeline Transportation of Solids", Proceedings: Eleventh Annual Dominion-Provincial Coal Research Conference (Saskatoon: 1959), pp. 92-110.

"Where coal and other fuels are equally available at the load centre, the competitive position of coal will almost always be improved by locating a plant at the mine and transmitting the power. This will be particularly true if the plant is designed for a base load. Where gas is available as a fuel, it will almost always be preferable to locate the plant at the load centre and transmit the gas. The distance over which such transmission is feasible will depend upon the spread between gathered gas prices at the field and the coal price at the load centre".¹⁵

In the decision of the City of Edmonton regarding the source of fuel, coal or gas, to be used in the City's proposed capacity expansion, the considerations of comparative costs included the capital costs that would have been involved in building HV transmission lines from Genesee and in bringing the coal deposits (leased) into production. At present, coal and natural gas prices are almost identical (per Btu.) and since natural gas can be pipelined to Edmonton at relatively low costs, the short-run cost structure favours natural gas as a fuel rather than coal. The higher capital costs associated with coal units in the short-run apparently are sufficient to out-weigh long-run savings in fuel costs associated with coal-fired generating units. It must also be remembered that expanding an established plant can be relatively less costly than building a completely new plant.¹⁶ This is parti-

¹⁵ David Cass-Beggs, Op. Cit., p. 108.

¹⁶ See Figure 4 p. 48.

cularly true when it is considered that the additional gross capacity expansion anticipated in 1970 by the City of Edmonton, was only 150 MW.¹⁷ The decision of the City of Edmonton reflects that costs other than fuel costs are important. The decision of Calgary Power to utilize low cost gas rather than coal at that company's first two Wabamun units was made under similar circumstances.

There are a number of coal deposits in Alberta which are of sufficient size to provide continuous supplies of coal at low and roughly constant costs over a period of 35 to 40 years which is the normal life of thermal electric units.¹⁸ Since most of these coal deposits are located less than 200 miles from regions of heavy electrical demand, a number of factors determine the order in which the deposits will be utilized by the electrical genera-

17

See Appendix B, p. 92.

18

North and South Wabamun, Forestburg, Genesee, and Sheerness are known fields containing sufficient reserves of 'mineable' coal. Ardley and Tofield fields may also contain the necessary reserves and it is quite possible that other fields may be discovered and may be exploited to supply fuel to thermal electric generating units. Interview with J.D. Campbell, Paleobotanist, Research Council of Alberta, May 8, 1965. Dr. Campbell feels however, that as the few truly desirable fields which lend themselves to strip-mining methods are exploited to capacity, underground mines may become competitive with other strip-mined coal fields (on the basis of cost per Btu.).

tion industry.

A 'cooling water' supply is most important at the present level of technology. This factor has been important in the decisions to locate the two large coal-fired thermal electric plants at Wabamun and Battle River. Part of the present generation capacity of the Drumheller plant was installed in 1948 and the Red Deer River was utilized as the cooling water source. The plant is relatively small, however, and its water consumption rather insignificant. The proposed Ardley development was to have a capacity of 500 MW and its water consumption would have been more significant. As was stated earlier,¹⁹ the concern of the Provincial Government regarding the shortage of water resources in Southern Alberta has become more intense of late. This concern affects thermal plants to an even greater degree than hydro facilities since hydro plants are responsible for less evaporation than thermal plants.

There is no large source of water in the vicinity of Sheerness. These deposits therefore do not warrant the location of generating plant at Sheerness although coal production costs at the Great West Coal Company strip-mine are relatively low.²⁰ The ultimate utilization of several otherwise ideal coal deposits will have to await

¹⁹

See pp. 30 - 31.

²⁰

See Appendix D, Par. No. 4, p. 98.

sufficient technological improvements in air-cooled steam-turbine generating units before these deposits are likely to be utilized to any great extent.²¹

While cooling water requirements may be of less consequence in the future, the coal deposit to be utilized must provide an adequate long-run supply of coal which is uniform in quality. The absolute quality of the coal is not as crucial as the consistency of the quality. Since coal-burning units can be designed to burn low grade coal, they are normally designed to burn the lowest grade of coal of the deposit at which the plant will stand. Higher grade coal can be burned but coal of grades lower than the grade for which the unit was designed must not be used if damage to the equipment is to be avoided. For this reason some electrical utility firms locate only where the firm has the mineral rights to sufficient reserves of constant quality coal to last for the life of the unit or plant. This is also the reason why electrical utility firms generally contract to buy from only one or two coal-producing firms in the same area if the utility firm itself does not develop the coal deposit. The electrical generation industry has been a major customer for coals generally unsuited for other uses, however, reserves of uniform quality coal must be available for at least the life of the generation unit and preferably for the life of the capital mining equip-

²¹ David Cass-Beggs, Op. Cit., p. 107

ment²² which often exceeds the life of the generating unit.

Uniform coal quality at constant mining costs must be available to an electrical generation plant for 35 years or more before the coal deposit is likely to be developed.

Road and rail facilities to the mine are also considered in decisions to develop coal deposits for the purpose of supplying fuel to electrical generation plants. The Wabamun site is located on the CNR main line, Edmonton-Vancouver, and No. 16 Highway. The Forestburg area mines initially lacked rail facilities but, in 1950, the CNR constructed a spur line to the tipple of Forestburg Collieries. Rail and road facilities are used to bring in heavy equipment, maintenance requirements and personnel as well as to haul coal to distant markets.

Wage rates throughout the strip-mining segment of the coal industry are the same and, therefore, they have little influence on decisions to invest in one location rather than another. Interest rates will influence the choice between various types of generating units. The greater the ratio of fixed cost to total cost, the more significant will be the interest level. Atomic energy plants and hydro-electric facilities are generally more capital intensive than thermal plants utilizing natural gas or coal. Plants designed to

22

G. H. Thompson, Op. Cit., p. 182

provide reserve capacity or peaking power are also associated with a high ratio of fixed to variable costs. In Alberta, new units or plants designed to provide reserve or peaking power are designed to burn natural gas as these units are lowest in capital cost. There is a contention that government-owned systems are subject to lower interest rates relative to privately-owned utilities and therefore, the former systems will be the first to invest in generating plants which are associated with high fixed to variable cost ratios.

"The lower costs of capital charges in government-owned systems would justify the addition of atomic energy plants on such systems before their use by privately-owned utilities".²³

While interest rates are important at the margin, there is evidence that combined sinking fund-interest charge allowances remain the same over a wide range of interest rates.

"Fixed costs include primarily the capital costs of interest charges and depreciation on the whole plant investment. For this purpose 6% has been used as a combined sinking fund and interest charge which does not vary much for interest rates between $3\frac{1}{2}\%$ and 5%. A life of 35 years is taken, at the end of which time it is assumed that the original investment will have been completely retired".²⁴

²³ A.G. Christie, "The Role of Thermal Power and the Place of Coal in Canada's Energy Program", Proceedings: Ninth Annual Dominion-Provincial Coal Research Conference (Edmonton: 1957), p. 52.

²⁴ David Cass-Beggs, Op. Cit., p. 103.

The decision to invest in coal-fired electrical generation plants involves a great number of considerations. Where a base load plant is being considered, the major considerations involve the additional unit size which is warranted in view of the anticipated demand for electricity on the system as a whole. Once the size of the additional unit is decided, the choice of fuel for the additional unit becomes the most important factor as, in base plants, even small differentials in fuel costs become important in the long run. If coal is the selected fuel base, location of the plant depends upon the location of the load centre to be served, the cost of transportation-transmission of coal versus electricity, and the relative physical features associated with a number of alternative coal deposits. Cooling water, the quality consistency of coal deposits, the adaptability of alternative coal deposits to large-scale strip-mining techniques, and the existing transportation facilities connecting the mine to major suppliers of equipment and to consumers of the coal are all important physical features which must be considered. The electrical utility firm involved in the investment decision must decide between developing the coal deposit itself or purchasing its coal requirements from independent coal mining firms. The long-range stability of coal costs must be assured whether the company produces its own fuel requirements, or coal is supplied by independent coal mining companies.

While interest and wage rates are considered in their investment decisions, private electrical utility firms in Alberta view these variables as constant throughout the area relevant to the production of electricity by means of coal-fired generation units. Because coal appears to offer the lowest long-run fuel costs, electrical firms consider coal to be the major source of future electrical generation in Alberta. The effects of the derived demand for coal on the part of the electrical generation industry are examined in the following chapter.

CHAPTER IV

PROJECTED COAL DEMAND by the ELECTRICAL GENERATION INDUSTRY in ALBERTA

While it is admitted that long-run projections may vary considerably from actual future activity, this chapter estimates the additional demand for coal associated with proposed additions and expansions to the coal-fired thermal capacity of the electrical generation industry in Alberta. Throughout this chapter, the 'Energy Schedule' and 'Generation Schedule' prepared by the electrical generation industry in Alberta will be used as an indication of the probable future electrical supply and demand. The schedules appear in their complete form in Appendix B.

It is assumed that the industry has accurately projected the demand for electricity in the future and that both the extrapolation of past trends and 'expert' evaluation of future possibilities were considered when the demand projection was drawn up. Likewise it is assumed that all known or anticipated factors have been considered by the constituent firms when additions to the total capacity of the Alberta electrical generation industry were projected. All figures given in the schedules (projections) are in gross rather than net figures. (Schedules courtesy of Calgary Power Ltd.).

Taking the projected additions to generating capacity as given, the projected demand for coal is assumed to depend on the operations of those plants which are and are planned to be located at Drumheller, Forestburg, North Wabamun, South Wabamun, Genesee and Sheerness.

For ease of reference, Table 4 on page 69 lists the present and anticipated coal-based electrical generation capacity in Alberta.

The demand for coal by the electrical generation industry is computed on the assumption that the average coal heat value per pound is as follows: at North Wabamun, South Wabamun, and Genesee, 8,000 Btu. per pound of coal; at Forestburg, 8,500 Btu. per pound of coal; at Sheerness, 9,000 Btu. per pound of coal; and at Drumheller, 10,000 Btu. per pound of coal.

Appendix O illustrates the relative improvement in thermal efficiency associated with increased turbine capacity (MW) and with reheat adaption. It is assumed that turbines rated at 150 MW, without reheat, generate electricity at 12,000 Btu. per KWH but that the same size turbine with reheat requires 11,000 Btu. per KWH. All turbine units which are scheduled to 'come on to line' after 1966 are assumed to incorporate reheat facilities. The 300 MW capacity units are assumed to require 10,000 Btu. per KWH. The projected additions to energy output (KWH) as outlined in Table 5, items 7 to 13 in-

Table 4

PRESENT AND ANTICIPATED COAL BASED ELECTRICAL
GENERATION CAPACITY IN ALBERTA

Item	Date	Company	Location	Incremental Capacity in Gross M.W.	Projected Energy Addition.. Gross K.W.H.
1	1946	CUL	Drumheller	2.0	
2	1947	CUL	Drumheller	8.25	
3	1952	CUL	Drumheller	8.25	
4	1956	CUL	Battle River	35.0	
5	1962	CPL	N. Wabamun	155.0	
6	1964	CUL	Battle River	35.0	
7	1967	CPL	N. Wabamun	300.0	2,234
8	1969	CUL	Battle River	150.0	1.117
9	1972	CPL	N. Wabamun	300.0	2,234
10	1973	CUL	Battle River	150.0	1.117
11	1974	CPL	S. Wabamun	300.0	2,234
12	1975	C of E	Genesee	150.0	1.117
13	1979	C of E	Genesee	150.0	1.117

Note: CUL...Canadian Utilities Ltd., CPL...Calgary Power Ltd.,
C of E...City of Edmonton.

Source: Appendix A. p.88
Appendix B. p.92

clusive, are converted to the tons of coal required under the above assumptions and assuming a 100% load factor.

$$\begin{array}{l} \text{Gross Energy Addition} \\ \text{(KWH's)} \end{array} \times \frac{\text{Btu. required per KWH}}{\text{Btu. per ton}} = \begin{array}{l} \text{Additional Demand} \\ \text{for Coal} \end{array}$$

The projected demand for coal in coal-fired generation units now in operation is assumed to remain at much the same level as has prevailed in the past. The three Drumheller units (Table 4, items 1 to 3 inclusive) are therefore expected to require 65,000 tons of coal per year.¹ The two 35 MW units at Battle River (Table 4, items 4 and 6) are expected to continue to require approximately 115,000 tons of coal per year each.² The coal-fired 155 MW generator of Calgary

¹ Based on the average consumption, 1960 to and including 1964. The Alberta Power Commission, Annual Report (Edmonton: annual).
1960 57,760 tons 1963 81,902 tons
1961 69,009 tons 1964 52,428 tons
1962 67,521 tons

Also based on Interview with Wilson Sterling, Engineer, Canadian Utilities Ltd., Aug. 10, 1965.

² Ibid.
1960 146,606 tons 1963 170,013 tons
1961 153,959 tons 1964 227,807 tons
1962 144,000 tons

These statistics are adjusted to include other estimates: The Transmitter, Op. Cit.

Interview with Peter Cullimore, Pres., Forestburg Collieries Ltd., Aug. 19, 1965.

Also see Appendix D, p. 98.

Power is expected to consume 800,000 tons per year.³ In each of the now operational plants, the prevailing Local Factor is assumed to be continued although the least efficient thermal plants (those with the highest marginal costs) will be relegated to an 'emergency reserve' or 'peaking' role as time passes.⁴

In 1977, the plant of East Kootenay Power Ltd. (E.K.P.) will be retired. Although Alberta coal is utilized in this plant at Sentinel, most of the generated electricity is exported to British Columbia.⁵ Figure 6 on page 73, is a projected demand for coal, for use in electrical generation by Mr. MacGregor, Chairman of the Alberta Power Commission who has included the E.K.P. coal demand.

In this thesis, the E.K.P. coal demand and the Saskatchewan Power Corporation demand for Alberta coal have not been included. While the demand for coal of these two utility companies is signi-

3

Alberta Power Commission, Annual Report (Edmonton: annual).

1962 140,150 tons

1963 317,997 tons

1964 814,144 tons

These estimates are adjusted to include the estimate of Mr. G.H. Thompson, Op. Cit., p. 182.

4

Cass-Beggs, Op. Cit., p. 103.

5

The Alberta Power Commission, Annual Report, 1964 (Edmonton: 1965), p. 15.

Table 5

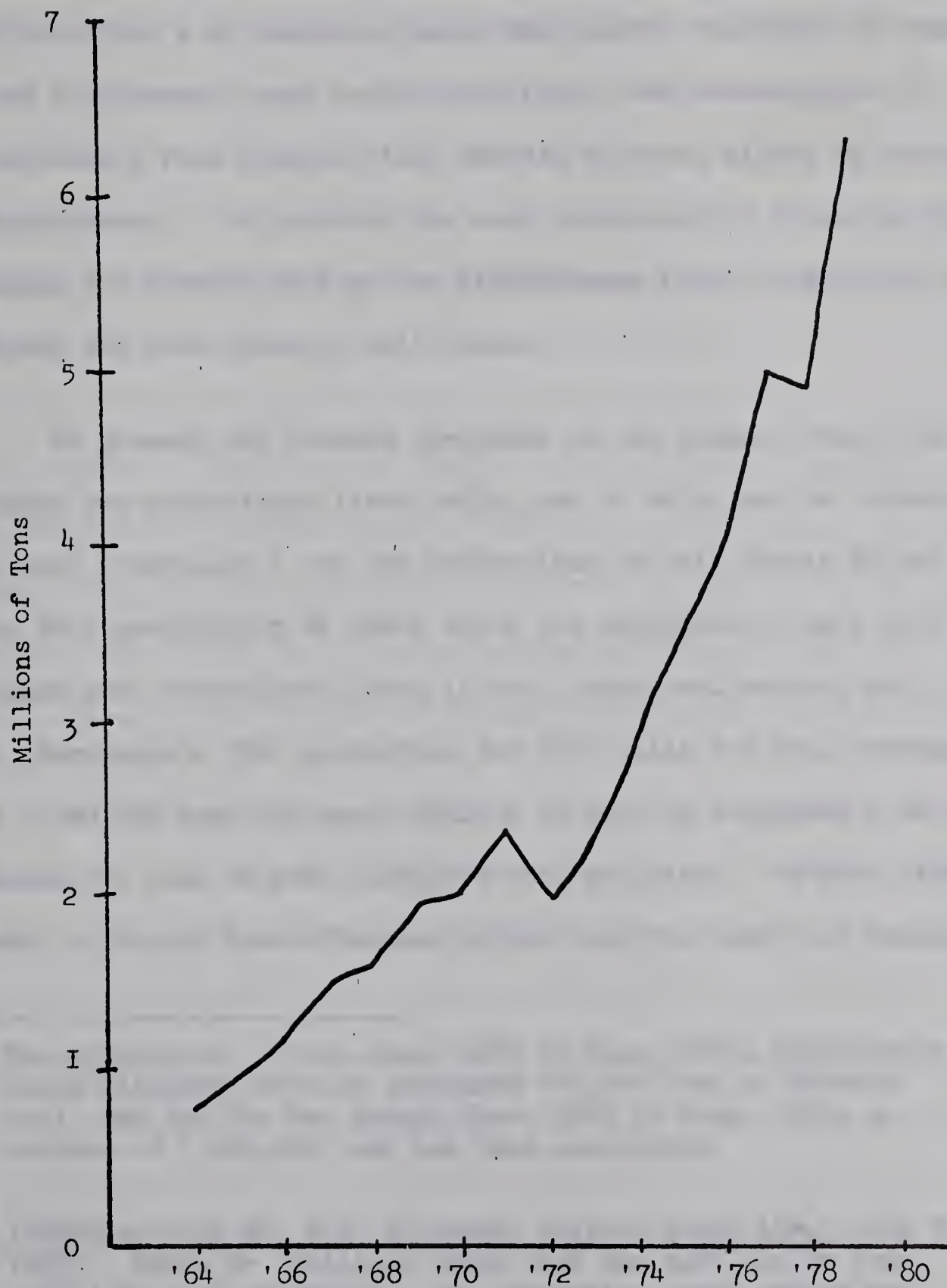
PROJECTED DEMAND FOR COAL BY THE ELECTRICAL UTILITY
INDUSTRY IN ALBERTA...1966 - 1980...at 100% Load Factor

Item	Year	Company	Location	Initial and Additional Demand (000's tons)	Total Demand (000's)
1	1966	CUL	Drumheller	65	
		CUL	Battle River	230	
		CPL	N. Wabamun	800	1,095
2	1967	CPL	N. Wabamun	1396	2,491
3	1969	CUL	Battle River	723	3,204
4	1972	CPL	N. Wabamun	1396	4,610
5	1973	CUL	Battle River	723	5,333
6	1974	CPL	S. Wabamun	1396	6,729
7	1975	C of E	Genesee	768	7,497
8	1979	C of E	Genesee	768	8,265
Total annual demand in 1980.....					8,265

Source: Appendix B. p. 92 and formula, p. 69.

Figure 6

FORECAST OF COAL TO BE USED FOR ELECTRICAL
POWER GENERATION IN ALBERTA



Source: J.G. MacGregor, "Coal For Electricity In Alberta",
Proceedings...Sixteenth Dominion-Provincial Conference
on Coal (Ottawa; 1965), pp. 196-206.

nificant in the short-run,⁶ the delivered cost of 22 to 24 cents per million Btu.'s in Saskatoon makes this market vulnerable to competition from natural gas, hydro-electricity, and transmission of electricity from lignite-fired thermal electric plants in southern Saskatchewan. To consider the many factors which determine the demand for Alberta coal by the Saskatchewan Power Corporation is beyond the main theme of this thesis.

At present the Wabamun operation of the Calgary Power Ltd. includes two natural-gas fired units, one of which may be converted to coal eventually,⁷ but the projections of this thesis do not allow for this possibility as these units are adaptable to meet peak load demand more conveniently than is the larger coal-burning unit. While Mr. MacGregor's 1964 projection for 1980 calls for coal consumption of 6,300,000 tons per year, Table 6 on page 72 indicates a derived demand for coal of some 8,265,000 tons per year. Of this difference, a 250,000 ton difference arises from the fact that Canadian

⁶ See Appendix L. From June, 1964 to June, 1965, Saskatoon's Queen Elizabeth station purchased 640,000 tons of Alberta coal, and for the two years, June, 1965 to June, 1967, a minimum of 1,000,000 tons has been contracted.

⁷ Interview with Mr. M.M. Williams, Calgary Power Ltd., July 20, 1965. While Mr. Williams feels that one unit may be converted to coal eventually, the conversion costs versus the potential savings in fuel costs do not yet justify conversion of either natural gas fired unit.

Utilities Ltd., in 1965, decided to add a 150 MW unit to their Battle River plant rather than the 75 MW unit anticipated one year earlier. The main reason for the variance in the two projections, however, involves the consideration of load factor on the coal-burning thermal units. Assuming that five percent of the fuel costs are fixed costs in thermal plants⁸ and assuming a load factor of 75 percent on all coal-burning units, 80 percent of the estimated 8,265,000 tons would be the demand for coal by the electrical industry in Alberta. Taking into account the change in the plans of Canadian Utilities and assuming a 75 percent load factor, Mr. MacGregor's projection (6,550,000 tons corrected) and the adjusted projection of Table 6 (6,612,000 tons at 75 percent load factor) are within one percent of each other.

In the projections of generation capacity to be added to the Alberta electrical industry by 1980, the most doubtful additions would appear to be the City of Edmonton-Genesee proposals for 1975 and 1979. Under the same assumptions and the same formula employed to derive Table 6, this 'lost' demand would amount to 1,636,000 tons per year. The electrical generation industry demand in 1980, without a Genesee plant, would be 6,629,000 tons at 100 percent L.F. and 4,796,000 tons at 75

⁸

David Cass Beggs, Op. Cit., p. 103.

percent L.F. The possible variance in demand is very great.

Year	L.F.	All units per Table 6	Without Genesee
1980	100%	8,265,000 tons	6,629,000 tons
1980	75%	6,612,000 tons	4,976,000 tons

By 1980, the demand for coal by the electrical generation industry generating in and supplying demand in Alberta, will likely be above 5 million tons per year. This estimate may be low considering that the 'Generation Schedule' projected a 600 MW interconnection (in 1976) with B.C. Hydro and this interconnection is now discounted by the Alberta Power Commission. Since thermal facilities require a shorter gestation period, construction to production, than do hydro facilities, part of the generation requirements may be provided by coal-fired unit expansion and/or higher Load Factor on scheduled coal-fired capacity.

Some of the possible variations in the projected demand for coal have been pointed out; this thesis acknowledges that exact projections cannot be made. While a minimum demand, in 1980, would appear to be 5 million tons per year, it is the purpose of this thesis to suggest that there is potentially a much greater demand for coal than the industry has ever known in the past. The demand for coal by the electrical generation industry will depend on the ability of the coal mining industry to produce coal at stable costs and consistent quality. There will be of course, competition

from other sources of electrical generation, but judging the future in the light of the present day, coal offers the electrical industry a low-cost energy source, and the electrical industry offers the coal mining industry a large and growing market. The market for coal is not likely to fluctuate widely from year to year around an increasing trend line but instead, coal will be used primarily to produce the 'base load' of the electrical system, and demand should increase at a stable rate.

In Chapter 5, the factors which determine the selection of plant load factor are explained. Knowing the factors which the electrical utility companies consider in their decisions to invest and in their decisions to allocate load among the various plants in the system will enable coal mining companies to better plan their own investment programmes.

CHAPTER V

CONCLUSION

In Chapter IV, projections of the demand for coal by the electrical generation industry in Alberta were made. That the high and low projections are so far apart has been explained, in part, by the fact that the coal-burning Genesee project of the City of Edmonton has been set aside in favour of an expansion of the natural gas plant at Edmonton. The load factor on the coal-fired plants also has a substantial effect on the amount of coal consumed by these plants. The major reasons why the City of Edmonton has selected natural gas rather than coal have been explained. What remains to be fully explained are the factors which will determine the load factor on coal-fired plants.

A. The Effect of Load Factor on Energy Source Consumption

Given the demand for electricity, the load on the system as a whole must be allocated among the various plants in the system so as to minimize total marginal costs, ceteris paribus.

"The maximum amount of energy will be assigned to the plant with the lowest variable cost." ¹

a. Load Factor on Hydro Facilities:

In Alberta, the hydro-electric plants have the lowest variable

¹ David Cass-Beggs, Op. Cit., p.103

costs (and the highest fixed costs) but these plants are assigned peaking and emergency reserve roles rather than the base load role. The capacity of the hydro-electric plants is not sufficient to provide all the base load at any given time. These plants, in fact, are limited in their output despite their capacities.

All hydro-electric plants in Alberta are associated with large dams and resevoirs. The utilization of the capacity of the plant depends upon the level of the reservoir and the continual replenishment of the supply of water in the resevoir is crucial. The rivers of Alberta are intermittant throughout the year and therefore the capacity of the hydro-plants can only be utilized fully during the spring and the summer run-off. The hydro-plants are not capable of generating electricity continuously and combined with the fact that the total hydro capacity is insufficient to provide all the electricity demanded, this necessitates less intermittent generating capacity.

The other limiting factor to the utilization of hydro resources for the sole purpose of generating electricity is the low social priority (as stated by the Provincial Government) assigned the use of hydro resources for the generation of electricity.

"Recently considerable attention has been focused on large river diversion schemes affecting all our streams which rise in the mountains, and these

studies are very timely --- (In) our existing Water Resources legislation the use of water for generating power ranks fifth in the list of priorities --- being outranked by domestic, municipal, industrial and irrigation purposes." ²

As an example of dual-purpose river dams, the Brazeau River Dam has been constructed to control downstream pollution (on the Saskatchewan River east of Edmonton) as well as to generate electricity.

Hydro generating facilities are ideal, on the other hand, to supply peaking power and emergency reserve capacity. Hydro facilities are centrally controlled (with the exception of the Spray and Brazeau facilities) in Seebe and can 'come onto line' in a matter of seconds. Thermal facilities, on the other hand, may require many hours to reach pressure and temperature requirements to begin generation; this is particularly true of coal-fired generating facilities. Assuming that the pricing policy of the electrical generation industry is designed to cover short-run average costs (including the Provincially limited profits) and assuming that the electrical generation industry is committed to providing electricity during peak demand periods and over emergency replacement periods, this peak and emergency electricity is generated most economically by hydro facilities. The alternative of keeping thermal facilities at near generation pressures and temperatures in order to supply peak or

² Alberta Power Commission, Annual Report, 1965 (Edmonton: 1966), p. 37

emergency power is apparently more costly assuming that the industry attempts to minimize average costs.

"Minimum power production costs are obtained by Calgary Power when thermal-electric and hydro-electric plants are integrated with the thermal plants carrying the base load and hydro plants the peak load." ³

b. Load Factor on Natural Gas Generating Units:

If the price which electrical generation firms must pay for natural gas increases, as expected,⁴ and coal prices remain stable or decrease, coal-fired thermal electric facilities will provide that base load power of which the hydro electric facilities are incapable, given the above mentioned restraints. Natural gas-fired thermal facilities are more versatile than coal units in their capability of rapidly building-up steam. Because natural gas prices (per heat unit) are expected to rise relative to coal, it is expected that the marginal costs in these plants will be relatively higher than in coal-fired plants and therefore natural gas-fired plants will more and more assume the role of supplying peaking power (and perhaps part of the emergency reserve).

³ M.M. Williams, Op. Cit., p.1.

⁴ G.H. Thompson, Op. Cit., p. 182, and M.M. Williams, Op. Cit., pp. 1-2.

c. Load Factor on Coal-Fired Generating Units:

Coal-fired thermal electric generating units are the least desirable of the three alternative generation facilities insofar as stand-by or emergency reserve is concerned because they are slow to accelerate to maximum capacity output. Because coal appears to offer the lowest fuel costs, however, coal-fired electrical plants offer the most economical thermal electrical generation. Because of the restraints on the utilization of hydro facilities and because existing hydro facilities are incapable of supplying the total base load demand, it would appear that coal-fired electrical plants will continue to be used to supply base load power, at high plant load factor, in the future.

In the investment decisions regarding additions to the capacity of the system it would appear, ceteris paribus, that the facilities which provide the lowest marginal costs at full capacity output would be the logical choice; this would imply that hydro facilities should be considered first. Transmission costs, however, would be the most important marginal costs considering the distance from load centres of the suitable hydro sites remaining in Alberta. At present and foreseeable electrical demands, it is doubtful whether the load factor on the hydro facilities, and on the Extremely High Voltage lines that would be required, would justify remote hydro-electric generation. As an example, Hudson Hope hydro generation facilities are

as close to Edmonton as some of the more desirable Athabaska hydro sites but the Alberta Power Commission feels that Hudson Hope power will not be imported into the Edmonton area.

"There has been some discussion about building an E.H.V. line to send power into the Edmonton area from Hudson Hope, but it is doubtful if this would be economical."⁵

B. Conclusion

While private electrical generation firms in Alberta are restricted in their profit levels, it is reasonable to expect that both the private firms and the municipal firms which make up the industry in Alberta must cover their average costs from year to year. This being the case, it is unlikely that excess capacity will be contemplated without subsidies from higher levels of government. Since hydro dams must be fully completed before any electric energy can be produced, hydro-dams of large scale and at distant locations will have to await the day when total demand is sufficient to utilize their capacity at a load factor sufficient to cover average costs, assuming price increases of electricity are restricted by the Alberta Provincial Government at least indirectly.

⁵ Alberta Power Commission, Op. Cit., p. 32.

The alternative sources of additional base power generation, in the next fifteen to twenty years, will be natural gas and coal. Since coal is expected to be relatively lower in costs ⁶ than natural gas and since fuel costs are crucial in base load thermal plants, the number of coal-fired electrical generation plants will tend to increase relative to both hydro and natural gas plants (i.e. plant capacity) for some time to come. It is impossible, however, to foresee technical advances which may occur in the post-1980 period.

A major breakthrough in natural gas electrical generation; changes in hydro resources policies and improvements in electrical transmission efficiency; advances in small scale atomic power electrical generation plants; and improvements in liquid coke transport and burning facilities will make any projection made herein rather meaningless. The electrical generation industry is flexible enough to take advantage of new developments in the long-run period.

⁶

The recent tax rebate on public utilities, including natural gas, will be distributed among consumers in proportion to what they now pay. Domestic, commercial, and lastly industrial (including sales to electrical generation companies) will benefit in that order. The natural gas prices paid by electrical utility companies which generate thermal power based on natural gas are now in a favoured price category due to the high load factor which their demands afford gas pipelines. For a criticism of this pricing policy and for an examination of past natural gas price trends in the U.S.A. see W.C. Whittaker, "An Outline of Already Developed Trends in the U.S.A. as an Index of Future Canadian Trends in Natural Gas Distribution", Proceedings, Tenth Annual Dominion-Provincial Conference on Coal, 1958 (Fredericton; 1958).

The production and transport costs of liquid coke from the Athabaska tar sands are still unknown, but the potential use of liquid coke as a fuel in thermal electric generation cannot be ruled out. The experience in nuclear energy is more definite and, in extremely large plants, costs of electricity generated in this manner are becoming competitive in some areas. Again the load factor on plant is of great importance in an industry which aims to cover average costs in the short-run.

"Somewhere after 1990, when loads are large enough to enable a large nuclear plant to operate at a high load factor, such a plant may then be competitive with higher cost strip-coals which are still not committed for base load generation. But even after having installed the first nuclear plant, it would probably be advisable to build more coal-fired plants before building a second nuclear station."⁷

It would appear that coal as a fuel in electrical generation plants has a future for a period beyond 1980. The amount of coal that will eventually be consumed by the electrical generation industry rests to a large extent upon the efforts of the coal mining industry to keep the cost of coal at levels relatively lower than alternative fuels.

Because coal deposits in Alberta are adjacent to the centres of heavy electrical demand, improvements in pipe-line movement of coal (relative to electrical transmission) and large-scale low-cost

⁷ Alberta Power Commission, Op. Cit., p. 41.

mining of coal may improve the relative position of coal in competition with even nuclear power in the long-run. While strip-mining techniques have been emphasized in articles pertaining to the demand for coal on the part of the electrical generation industry, the higher heat value coal which can only be mined by underground methods may eventually provide the lowest cost (in cents per million Btu.'s) coal in Alberta.⁸ Multi-seam mining using highly capital intensive techniques may make this coal competitive for it is the cost per Btu. and not the cost per ton which decides this competitiveness.

The demand for coal by the electrical industry in Alberta ultimately depends upon the demand for electricity in Alberta and the cost competitiveness of alternative sources of electrical generation. Technological change may well alter the competitiveness of coal. In this thesis, analysis of trends in the demand for electricity and coal have been based upon developments in the recent past; however, the technological factors have also been examined

⁸ Interview with J.D. Campbell, Paleobotanist Research Council of Alberta, May 8, 1965. Dr. Campbell feels that centrally located (relative to electrical demand) underground mines with thick flat seams of coal may well be able to compete, in cost per Btu., with strip-mines in the future.

Interview with J.G. MacGregor, Chairman Alberta Power Commission, Apr. 17, 1965. Mr. MacGregor also feels that mechanized underground mines may well provide the cheapest pit-head coal prices in the future.

in order that the projections of the demand for coal take into consideration presently known technological limitations. Based on the trends and presently known technological considerations, the projections should provide an insight to future development of one sector of the coal industry in Alberta. In the longer run, the 'place in the sun' of coal depends on variables sufficiently complex to warrant greater study of the subject.

July 14th, 1965

Memorandum from T. D. Stanley

To Mr. F. T. Gale

Subject Capacity of interconnected System

For your information the following is a revised list of generating capacity of the interconnected system.

CALGARY POWER LTD.Hydro

<u>Date</u>	<u>Unit or Plant</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
1911	Horseshoe	14		
1913	Kananaskis	10		
1929	Ghost	28		
1942	Cascade	18		
Aug./47	Barrier	13		
July/51	Kananaskis Extension	9		
Oct./51	Three Sisters	3		
Oct./51	Spray	50		
Dec./51	Rundle	17		
Aug./54	Ghost Extension	23		
Dec./54	Bearspaw	17		
Oct./55	Interlakes	5		
Oct./55	Pocaterra	15		
Oct./57	Cascade Extension	18		
Nov./60	Rundle Extension	33		
Nov./60	Spray Extension	53		
Apr./65	Big Bend	165	491	490
Scheduled 1966	Big Bend	190	190	190

Thermal

<u>Date</u>	<u>Unit of Plant</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
Oct./56	Wabamun 1st unit	72		
Oct./58	Wabamun 2nd unit	72		
Oct./62	Wabamun 3rd unit	155	299	283
Scheduled 1967	Wabamun 4th unit	300	300	285

CITY OF EDMONTON

<u>Date</u>	<u>Unit</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
1939	Unit	15		
1944	Unit added	15		
Aug./49	Unit added	30		
Sept./53	Unit added	30		
Nov./55	Unit added	30		
Oct./58	Unit added	30		
Aug./59	Unit added	30		
Oct./60	Unit added	75		
July/63	Unit added	75	330	315
Scheduled 1966		75	75	70

CITY OF LETHBRIDGE

<u>Date</u>	<u>Unit</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
1931	Unit	3		
1943	Unit added	4		
May/53	Unit added	5		
Feb./58	Unit added	9		
Dec./60	Unit added	9	31	31

CANADIAN UTILITIES (DRUMHELLER)

<u>Date</u>	<u>Unit</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
1946	Unit	2		
Nov./47	Unit added	8		
Dec./52	Unit added	8	19	18

CANADIAN UTILITIES (VERMILION)

<u>Date</u>	<u>Unit</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
Nov./48	Unit	3		
Dec./58	Unit added	3		
Sept./49	Unit added	3		
Sept./49	Unit added	3		
Jan./62	Unit added	30	40	39

CANADIAN UTILITIES (BATTLE RIVER)

<u>Date</u>	<u>Unit</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
Dec./56	Unit	35		
June/64	Unit added	35	70	66
Scheduled 1969		150	150	145

CANADIAN UTILITIES (STURGEON)

<u>Date</u>	<u>Unit</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
1958	Unit	10		
June/61	Unit added	9	19	19

CANADIAN UTILITIES (GRAND PRAIRIE)

<u>Date</u>	<u>Unit</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
1948	Unit	1		
1950	Unit added	1		
1955	Unit added	3	4	4

CANADIAN UTILITIES - NORTHLAND (FAIRVIEW)

<u>Date</u>	<u>Unit</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
Nov./54	Unit	1		
Nov./54	Unit added	1		
Oct./57	Unit added	3		
June/59	Unit added	3		
Nov./60	Unit added	3	11	11

CANADIAN UTILITIES - PEACE RIVER

<u>Date</u>	<u>Unit</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
Scheduled 1966		20	20	19

- 91 -
CITY OF MEDICINE HAT

<u>Date</u>	<u>Unit</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
1945	Unit	3		
Dec./48	Unit added	6		
Nov./53	Unit added	33	42	41

EAST KOOTENAY POWER (SENTINEL PLANT)

<u>Date</u>	<u>Unit</u>	<u>Increment Capacity KW 000's</u>	<u>Gross Capability KW 000's</u>	<u>Net Capability KW 000's</u>
1927	Unit	6		
1929	Unit added	6	13	10

T. D. STANLEY

Note: Figures rounded-off to nearest 1000 KW

Source: Courtesy M.M. William of Calgary Power Ltd.

Appendix B

PROVINCE OF ALBERTA
ENERGY SCHEDULE

Year	Addition	Energy Addition KWH 10 ⁵	Total Energy KWH 10 ⁵
1969			10,908,828
1970	City of Edmonton Thermal 150 MW	1,116,900	"
1971	-	-	12,025,728
1972	C.P. Ltd. Thermal 300 MW	2,233,800	"
1973	Canadian Utilities Thermal 150 MW	1,116,900	14,259,528
1974	C.P. Thermal 300 MW	2,233,800	15,376,428
1975	City of Edmonton Thermal 150 MW	1,116,900	17,610,228
1976	(Retire 10) C.U. Ltd. Diesel)	(74,460)	
	B.C. Hydro Interconnection 600 MW	-	18,727,128
1977	(Retire 10) E.K.P. Thermal	(74,460)	18,652,668
1978	C.U. Ltd. Hydro 180 MW	890,000	18,578,208
1979	City of Edmonton Thermal 150 MW	1,116,900	19,468,208
	Med. Hat Thermal 150 MW	1,116,900	
1980	Big Bend 3 190 MW	-	21,702,008
	Brazeau Forks 105 MW	300,000	
1981	Big Bend 4 190 MW	-	22,002,008
	City of Edmonton Thermal 300 MW	2,233,800	
1982	C.U. Ltd. Hydro 180 MW	-	24,235,808
1983	C.P. Ltd. Thermal 500 MW	3,723,000	"
1984	Big Bend 5 190 MW	-	27,958,808

Year	Addition	Energy Addition KWH 10 ³	Total Energy KWH 10 ³
1985	City of Edmonton Thermal 500 MW	3,723,000	27,958,808
1986	C.U. Ltd. Hydro 510 MW	2,610,000	31,681,808
1987	C.P. Ltd. Thermal 500 MW	3,723,000	34,291,808
1988	City of Edmonton Thermal 500 MW	3,723,000	38,014,808
	C.P. Ltd. Hydro 190 MW	-	
1989	C.P. Ltd. Thermal 500 MW	3,723,000	41,737,808
1990	C.U. Ltd. Thermal 300 MW	2,233,800	45,460,808
1991	C.P. Ltd. Thermal 1000 MW	7,446,000	47,694,608
1992	C.P. Ltd. Hydro 190 MW	-	55,140,608
1993	C.P. Ltd. Thermal 1000 MW	7,446,000	"
1994	-	-	62,586,608
1995	City of Edmonton Thermal 1000 MW	7,446,000	"
1996	C.U. Ltd. Thermal 500 MW	3,723,000	70,032,608
1997	C.P. Ltd. Thermal 1000 MW	7,446,000	73,755,608
1998	City of Edmonton Thermal 1000 MW	7,446,000	81,201,608
1999	-	-	88,647,608

PROVINCE OF ALBERTA
GENERATION SCHEDULE

Calgary Power Ltd.
City of Med. Hat
City of Lethbridge
E.K.P.

Canadian Utilities City of Edmonton

Year	Addition	Total	Addition	Total	Addition	Total	Total
1969		1326.2		234		391	1951.2
1970		"		"	150 Thermal Edmonton	541	2101.2
1971		"	"	"		"	2101.2
1972	300 Thermal North Wabamun	1626.2		"		"	2401.2
1973		"	150 Thermal Forestburg	384		"	2551.2
1974	300 Thermal South Wabamun	1926.2		"		"	2851.2
1975		"		"	150 Thermal Genesee	691	3001.2
1976	B.C. Hydro 600 Intercon- nection	"	(Retire 10) Diesel	374		"	3591.2
1977	(Retire 10) E.K.P. Thermal	1916.2		"		"	3581.2
1978		"	180 Hydro Smokey River	554		"	3761.2
1979	150 Thermal Medicine Hat	2066.2		"	150 Thermal Genesee	841	4061.2
1980	190 Hydro Big Bend 3 105 Hydro Brazeau Forks	2361.2		"		"	4356.2
1981	190 Hydro Big Bend 4	2551.2		"	300 Thermal Genesee	1141	4846.2
1982		"	180 Hydro Smokey River	734		"	5026.2
1983	500 Thermal South Wabamun	3051.2		"		"	5526.2
1984	190 Hydro Big Bend 5	3241.2		"		"	5716.2

PROVINCE OF ALBERTA
GENERATION SCHEDULE

Calgary Power Ltd.
City of Med. Hat
City of Lethbridge
E.K.P.

			Canadian Utilities		City of Edmonton		
Year	Addition	Total	Addition	Total	Addition	Total	Total
1985		3241.2		734	500 Thermal Edmonton	1641	6216.2
1986		"	510 Hydro Smokey River	1244		"	6726.2
1987	500 Thermal South Wabamun	3741.2		"		"	7226.2
1988	190 Hydro Big Bend 6	3931.2		"	500 Thermal Edmonton	2141	7916.2
1989	500 Thermal South Wabamun	4431.2		"		"	8416.2
1990		"	300 Thermal Sheerness	1544		"	8716.2
1991	1000 Thermal Calgary	5431.2		"		"	9716.2
1992	190 Hydro Big Bend 7	5621.2		"		"	9906.2
1993	1000 Thermal Calgary	6621.2		"		"	10,906.2
1994		"		"		"	10,906.2
1995		"		"	1000 Thermal Edmonton	3141	11,906.2
1996		"	500 Thermal Sheerness	2044		"	12,406.2
1997	1000 Thermal Calgary	7621.2		"		"	13,406.2
1998		"		"	1000 Thermal Edmonton	4141	14,406.2
1999		"		"		"	14,406.2

Feb. 24/65
Rev. Mar. 25/65

AMALGAMATED COALS LIMITED

Miners and Shippers of

WESTERN MONARCH COAL AND NEW MIDLAND COAL

Mine Address
R.S. DRAWER 478
DRUMHELLER, ALBERTA

HEAD OFFICE
1503 - 15th Ave. West
CALGARY, Alberta

FROM THE DRUMHELLER VALLEY

East Coulee, Alberta
August 10, 1965

Mr. D.M. Poproski
6823 - 111 St.,
Edmonton, Alberta

Dear Sir:-

Your letter of August 3rd addressed to Mr. McMullen has been passed on to me here at the mine, as he is away on holidays. I will attempt to briefly answer the questions outlined in your letter and will return the letter to Mr. McMullen who I am sure will elaborate on the subject at his earliest opportunity.

To begin with I might suggest you contact a Dr. R.S. Ironside of the Dept. of Geography, University of Alberta as he was here only recently and took with him several reports that would possibly be of interest to you.

As to the specific questions in your letter:-

1. We are an underground mine, mining a seam of sub-bituminous coal approximately 12' thick. The mine is completely mechanized and we use a room and pillar extraction method. Our present equipment consists of 14 BU Joy loaders, 7 AU Joy Sullivan cutting machine, 6 ton battery locomotives for local and district haulage with trolley haulage on our main line. The coal is cut, shot with high compressed air (10,000 psi), loaded into 5 ton drop bottom cars and hauled out of the mine. It is then taken by truck to our tipple where it is cleaned and screened into various sizes and loaded into railroad cars. The only real physical labor involved is timbering and tracking places after they have been loaded out.

Our production capacity under present market conditions is approximately 2200 tons of coal per day. That tonnage would be attained by working three shifts underground and two on the surface. Our tonnage per man will average approximately 10 tons and on a working day will be as high as 14.

AMALGAMATED COALS LIMITED

Miners and Shippers of

WESTERN MONARCH COAL AND NEW MIDLAND COAL

HEAD OFFICE
1503 - 15th Ave. West
CALGARY, Alberta

Mine Address
P.O. DRAWER 470
DRUMHELLER, Alberta

FROM THE DRUMHELLER VALLEY

- 2 -

This is very brief and only a visit by you to the mine could make a complete picture possible. We would be only too pleased to have you visit us.

2. The type of coal mined from this area has always been used primarily for domestic purposes and at one time reached a tonnage of somewhere around 2,000,000 tons. With the advent of natural gas, cheapness of propane and oil, the domestic market has declined to the point where we are the only mine left in the valley and the tonnage has decreased to approximately 200,000 tons. As to the future we can see nothing to stop this decline in domestic sales, but the outlook for industrial outlets is improving. There are many possible uses for coal and I would suggest you contact Dr. Norbert Berkowitz of the Research Council of Alberta, who has written numerous articles on this subject. It is our hope that before the domestic end completely passes out of the picture, that we will find a large industrial outlet to take up the sag.

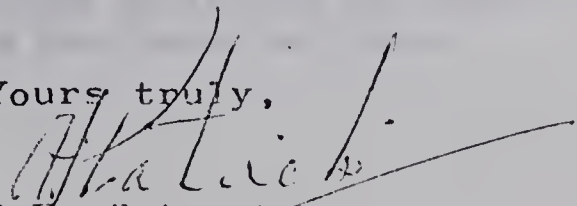
3. As to the future of the industry as a whole I believe very strongly in it. With the increasing demand for electrical energy and an increasing population who seem to like to do things with the flick of a switch I feel that the overall coal tonnage in the province will increase steadily. As to the underground mines future it is not too bright at the present moment and our particular companies' role in the future will be more in the strip mine end than the underground end.

As to other people to contact I would suggest:-

- (1) Mr. P. Cullimore of Luscar Coals who have offices in Edmonton
- (2) Mr. R.C. Sheldon of Weaver Coal Sales in Edmonton
- (3) Dr. N. Berkowitz who I have already mentioned
- (4) Dr. Ironside who presently has some of our files
- (5) Dept. of Mines & Minerals - Edmonton
- (6) Mr. J. Dutton - Director of Mines - Edmonton
- (7) Alberta Coal Sales - Lougheed Bldg., Calgary

I hope this brief outline will be of some assistance to you and would strongly suggest a visit to the mine if this particular end is of interest to you. If perchance you have an extra copy of your thesis when it is completed I would appreciate very much having one. Good luck.

Yours truly,


O.H. Patrick
General Manager

ALBERTA COAL LTD.

436 Lougheed Building
Calgary, Alberta

September 7, 1965

Mr. D. M. Paproski
6823 - 111 Street
Edmonton, Alberta

Dear Mr. Paproski:

Referring to your letter of August 18th, we will take up your questions in the same paragraph order.

Par. #1

The four operations controlled by this company produced 31% of total coal in Alberta in 1963 and 42% in 1964 according to our records and Dominion Bureau of Statistics figures.

Par. #2

Whitewood Mine tonnage for 1964 was 565,000 tons. Anticipated tonnage for 1965 is 875,000 tons.

Output per man day for 1964 was 60 tons. Tonnage forecast including 300 MW unit at 62% load factor = 2,000,000 tons. This assumes a heat rate of 12,000 B.T.U. per KW generated.

As to future operations at South Wabamun we can only approximate using 12,000 B.T.U. per Kwh generated and 8000 B.T.U. coal. Perhaps such a projection should also be based on a 50% load factor.

A sample calculation for a 300 MW unit would be about as follows:

$$300,000 \text{ Kwh} \times \frac{12000 \text{ BTU/KW}}{8000 \text{ BTU/lb.}} \times 24 \text{ hours} \times 365 \text{ days} \times 50\% = 490,000 \text{ tons}$$

Heat rates and load factors depend upon plant efficiency and power demand. The larger, more efficient plants may have heat rates as low as

Mr. D. M. Paproski
September 7, 1965
2

9000 BTU per Kwh and the load factor can be 70-80% before a new plant is built. We must refer you to Calgary Power for these estimates.

Costs again depend upon tonnage. A so-called mine mouth plant such as Wabamun can get coal at a cost of nine cents per million BTU's. Other plants not so favourably located or sized will have costs of 14 cents per million BTU's.

Par. #3

The Battle River Coal Company Limited at Halkirk produced 201,000 tons in 1964 equivalent to 25 tons per man day. 35% of this coal or 70,000 tons went to Canadian Utilities Forestburg plant. The remainder was sold as sized coal on the retail market.

The 150 MW unit scheduled to go on the line in 1969 will ultimately mean consumption of 750,000 tons of coal at this plant. Battle River Coal's share of this market will be one third or 250,000 tons. This share may be increased. The other markets will decline. We would expect this mine to produce about 400,000 tons per year after 1971.

Costs will be in the order of 13 cents per million B.T.U.

Par. #4

Great West Coal Company, Limited mine at Sheerness, Alberta production in 1964 was 178,000 tons and will be 207,000 in 1965.

Coal costs at the mine, excluding freight, are 12 cents per million B.T.U.

The Saskatchewan Power Corporation at Saskatoon will take 125,000 tons during 1965.

You apparently have a forecast by C.U.L. for expansion at Forestburg and Sheerness and can work out estimated tonnages as above. Again plant efficiency and load factors determine anticipated quantities and the power companies are best equipped to make such estimates.

Par. #5

Alberta Coal Sales Limited at Taber produced 26,000 tons in 1964 for domestic sale. 1965 production will be about 80,000 tons, largely due to shipments of coal to The Kimberley, B. C. iron plant of Consolidated Mining and Smelting Company of Canada Ltd. both as char and as sized coal.

During 1964 this mine produced at the rate of 15 tons per man day. This will improve during 1965.'

Mr. D. M. Paproski
September 7, 1965
3

Cost of mining coal at this mine is about 20 cents per million B.T.U.

This coal is a sub-bituminous "A" of about 10,100 B.T.U. per pound, high volatile and low ash, making it a desirable coal which will stand the increased cost caused by low tonnage.

Par. #6

With regard to markets, it is obvious from planned expansion now under way and projected that coal-fired thermal plants offer the best market for increased production. Please refer to published literature such as the "Annual Electric Power Survey of Capability and Load" by the Dominion Bureau of Statistics and publications of The Alberta Power Commission. Domestic consumption will decrease. Of interest for the future is increased activity by iron and steel producers in establishing steel plants in Western Canada based upon iron ores.

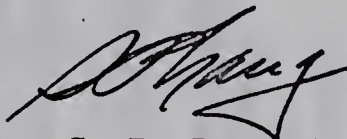
The iron plant of Consolidated Mining and Smelting Company of Canada Ltd. utilizes iron sinter as feed and high volatile sub-bituminous coal, coke and char as reducing agents.

In addition a steel company contemplates a plant in the Edmonton area using the Lurgi process for making sponge iron from pellets. This requires a high volatile sub-bituminous coal as well.

With regard to the Coal Branch area, this is high volatile bituminous coal of about 11,000 B.T.U. It is an excellent domestic and steam-raising fuel. Development of the area will depend upon additional markets for such coals. Pulp mills are certainly in the picture.

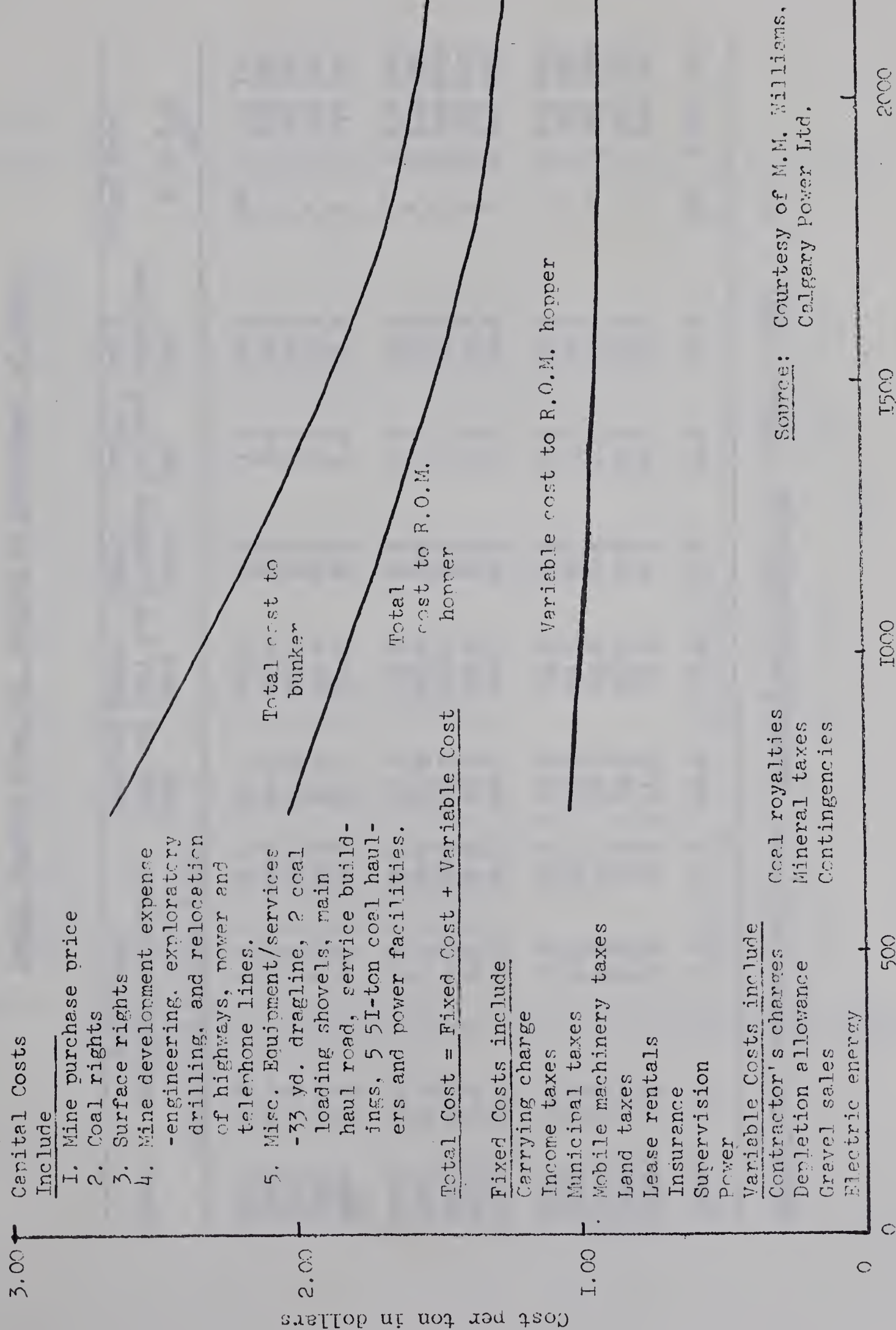
Yours very truly,

ALBERTA COAL LTD.



S. P. Lang, P. Eng,

SPL/wh



Appendix F

Energy Sources From 1945 to 1960 by Percentage of Total

Year	Solid Fuel		Imported Total		Hydro		Total		Grand Total	
	Canadian Production	Bituminous Lignite Total	Coal and Coke	Coal and Coke	Power	Electric	Natural Gas	Petroleum Fuel	%	B.T.H. 10 ¹⁰
1945	16.8	5.6	22.4	41.6	8.0		3.7	24.3	100	1 713 715
1946	16.9	5.7	22.6	40.0	7.8		3.4	26.2	"	1 832 925
1947	13.4	5.1	18.5	40.8	7.7		3.2	29.8	"	1 965 088
1948	15.5	4.5	20.0	39.4	6.9		3.3	30.4	"	2 172 566
1949	17.6	5.2	22.8	31.1	8.1		4.0	34.0	"	1 978 719
1950	14.9	5.0	19.9	33.2	7.8		3.9	35.2	"	2 234 960
1951	13.7	4.3	18.0	30.9	8.2		4.0	38.9	"	2 410 202
1952	12.8	4.0	16.8	28.2	8.6		4.6	41.8	"	2 454 948
1953	11.5	3.4	14.9	25.6	8.7		5.4	45.4	"	2 509 497
1954	10.5	3.5	14.0	20.8	9.5		6.5	49.2	"	2 465 979
1955	9.2	3.0	12.2	19.4	9.1		7.3	52.0	"	2 819 880
1956	7.9	2.5	10.4	18.8	8.3		7.6	54.9	"	3 345 983
1957	6.9	2.2	9.1	16.1	8.4		10.0	56.4	"	3 387 378
1958	6.3	2.2	8.5	12.5	9.7		14.4	54.9	"	3 195 178
1959	5.2	1.9	7.1	11.4	9.5		14.6	57.4	"	3 459 122
1960	5.3	1.7	7.0	10.2	9.8		16.6	56.4	100	3 665 329

Source: The Dominion Coal Board, Annual Report, 1960-1961 (Ottawa: 1961), p. 49

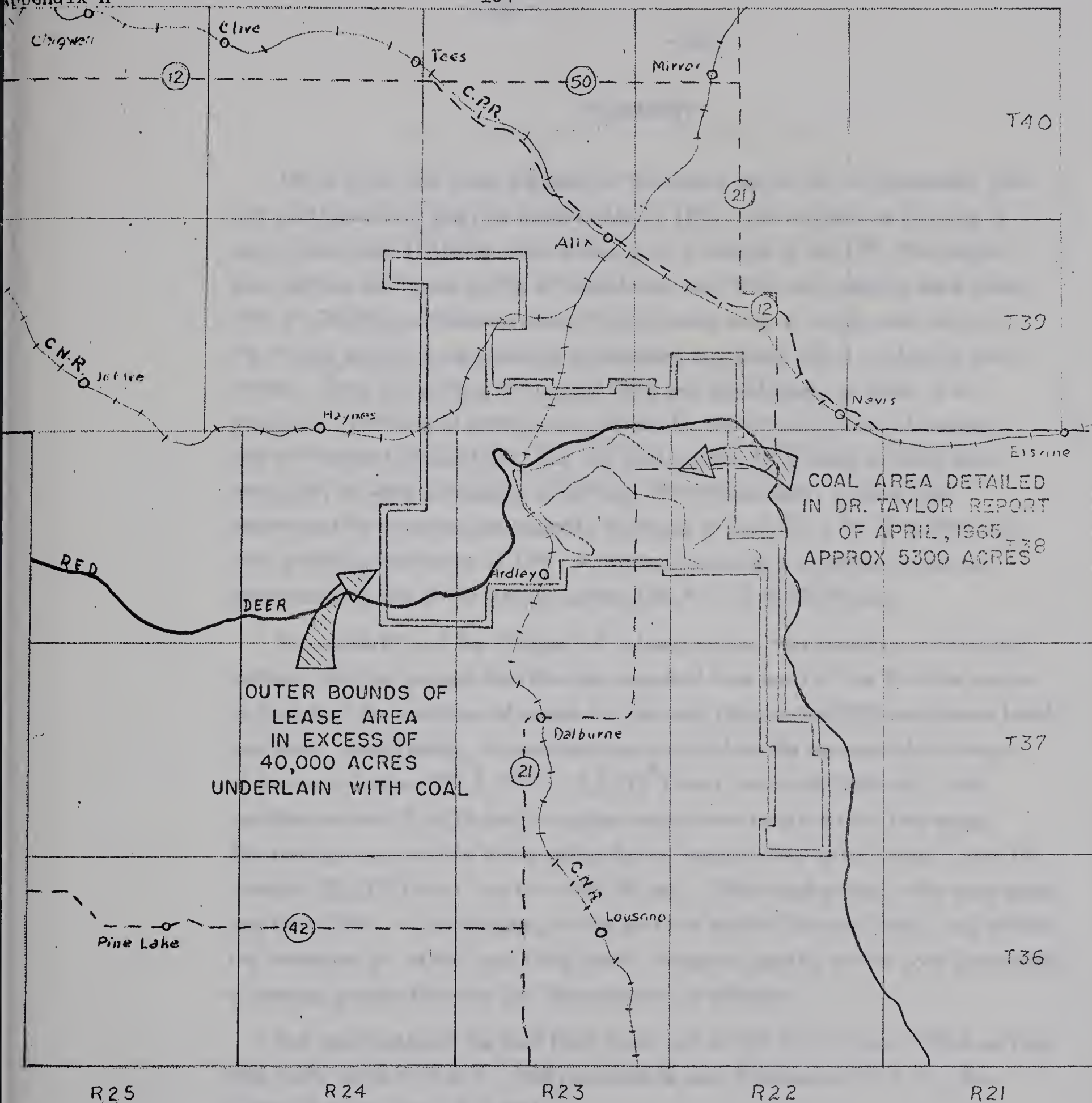
Appendix G

Estimated Savings in Fuel and Repair Costs...Diesel vs. Steam Locomotives

(Class I railroad in the United States...Year, 1957)

1	<u>Fuel:</u>	
2	Steam locomotives fuel consumed during year	
3	Coal (tons)	4 772 703
4	Fuel oil (barrels)	662 446
5	Estimated additional steam locomotive fuel required to handle work performed by diesel locomotives	
6	Coal (tons)	88 926 283
7	Fuel oil (barrels)	87 009 404
8	Unit cost of fuel	
9	Coal per ton	\$ 6.29
10	Fuel oil per barrel	\$ 2.91
11	Cost of additional steam locomotive fuel required to handle work performed by diesel locomotives	
12	Coal (6x9)	\$559 300 000
13	Fuel oil (7x10)	\$253 200 000
14	Total	\$812 500 000
15	Cost of diesel fuel actually consumed	\$383 500 000
16	Apparent saving attributable to diesels	\$429 000 000
17	<u>Repair Expense:</u>	
18	Cost of steam locomotive repairs	\$ 38 373 271
19	Estimated additional cost of steam locomotives repairs if work handled by diesels had been handled by steam locomotives	\$901 100 000
20	Actual cost of diesel locomotive repairs	\$453 400 000
21	Apparent saving attributable to diesels	\$447 700 000
22	Total estimated saving, fuel and repair costs only	\$876 700 000

Source: Burton N. Behling, "Railroads - Their Development, Problems and Prospects", U.S. Transportation Resources, Performance and Problems (Washington: 1962), Table 14.



ARDLEY COAL LIMITED

MAP SHOWING LEASE AREA
AND COAL AREA COVERED IN
DR. TAYLOR REPORT
DATED APRIL, 1965

SUMMARY

The drilling that forms the basis of this report started in mid-December 1964 and continued until the first week of March 1965, with as many as five rigs in use at one time. 419 holes were drilled with a footage of 55,179. The Ardley coal section was found in 396 of these holes, and 1724 coal samples were taken from it. Drilling outlined an area of 8.26 square miles in which coal occurs in the Ardley section in recoverable thicknesses and under 150 ft. or less of overburden. Once the outline of the coal field was established, 36 holes in an irregular 1/2-mile grid pattern were picked for analytical control of tonnage and ash-content calculations. The 161 coal samples from these 36 holes were analyzed, as were 32 samples of partings. With these data, a value was determined for maximum recoverable thickness of coal (17.1 ft. @ $\approx$ 30% ash) with a mining-loss factor of 15%. A similar recoverable thickness value was determined for the entire Ardley section (20.7 ft. @ $\approx$ 35.5% ash).

The reliability of the first pair of values, above, was tested by a statistical method. This test proved that the data acquired from each of the 36 holes was so uniform that the variation of values for the coal field at the 95% confidence level was small. Specifically, it permitted me to calculate the recoverable tonnage of the coal field as $187.5 (10^6) \pm 9.5 (10^6)$ short tons (at $\approx$ 30% ash), with confidence that 19 of 20 similar studies would have results within this range. The tonnage recoverable if the entire Ardley section were to be mined as one lift is about $235 (10^6)$ short tons (at $\approx$ 35.5% ash). Other coal exists in the area under less than 200 ft. of overburden, to the east and west of the coal field, and within the horseshoe arc of the coal field itself. However, quality of this coal (potentially a tonnage greater than the last figure above) is unknown.

The overburden of the coal field works out as 105.9 ft. thick. With a parting plus waste value of 7.0 ft., and recoverable coal thickness of 17.1 ft., the pertinent mining ratio is 6.60:1.

The quality of the coal within the coal field is now well-established. Moisture contents, calculated with the coal field divided into five smaller areas, range from 11.97% to 12.75%, with a mean for the whole field of 12.39%. A marked ash content - B.T.U./lb. relationship was found that holds closely through all observed values. This shows that at 35.5% ash, the expectable heat output of the mined product will be about 6800-7000 B.T.U./lb., and at 30% ash, 7500-7700 B.T.U./lb.

RECOMMENDATION AND CONCLUSIONS

1. It is recommended that all coal samples on hand be properly kept for future analysis of all 1320' - grid samples, to afford more detailed quality control.
2. Nothing of a geological nature has been noted in the area that would prevent this coal being strip-mined.
3. The mining ratio within the Ardley Coal Field is 6.60:1, a favourable one, with a maximum overburden thickness of 150 feet.
4. It is concluded, with 95% confidence, that the available tonnage in the Ardley Coal Field (at ~~2~~30% ash) is in excess of 178 million short tons.

BABCOCK-WILCOX AND GOLDIE-McCULLOCH, LIMITED

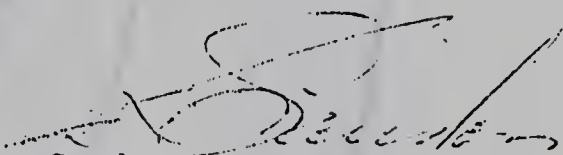
Dynamic Power Corporation Ltd., Calgary, Alberta.

April 27, 1965.

* 2 *

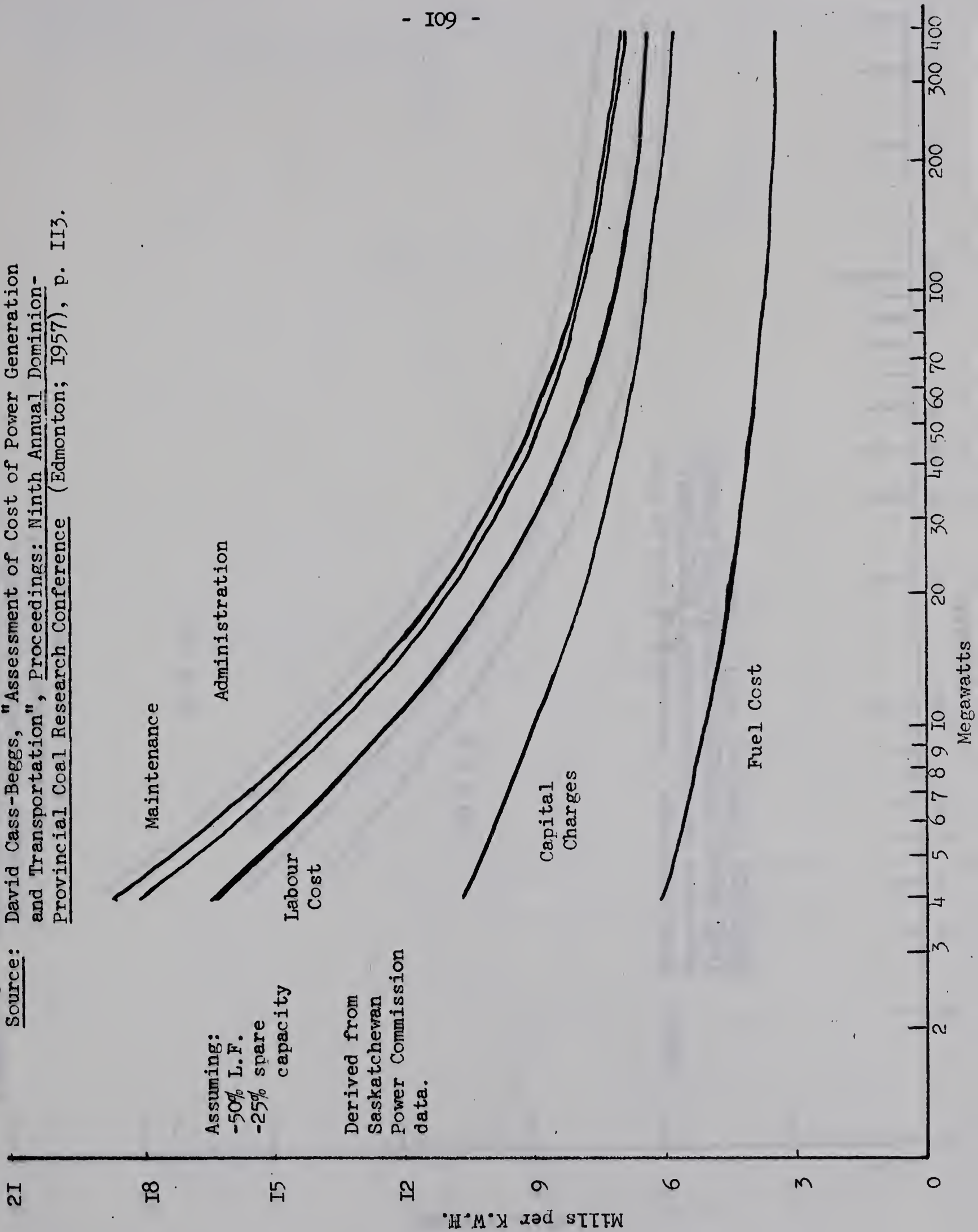
to hear from you. Meanwhile, we will make a point of calling on you in the near future and discussing the analysis in detail.

Yours very truly,
BABCOCK-WILCOX & GOLDIE-McCULLOCH, LIMITED.

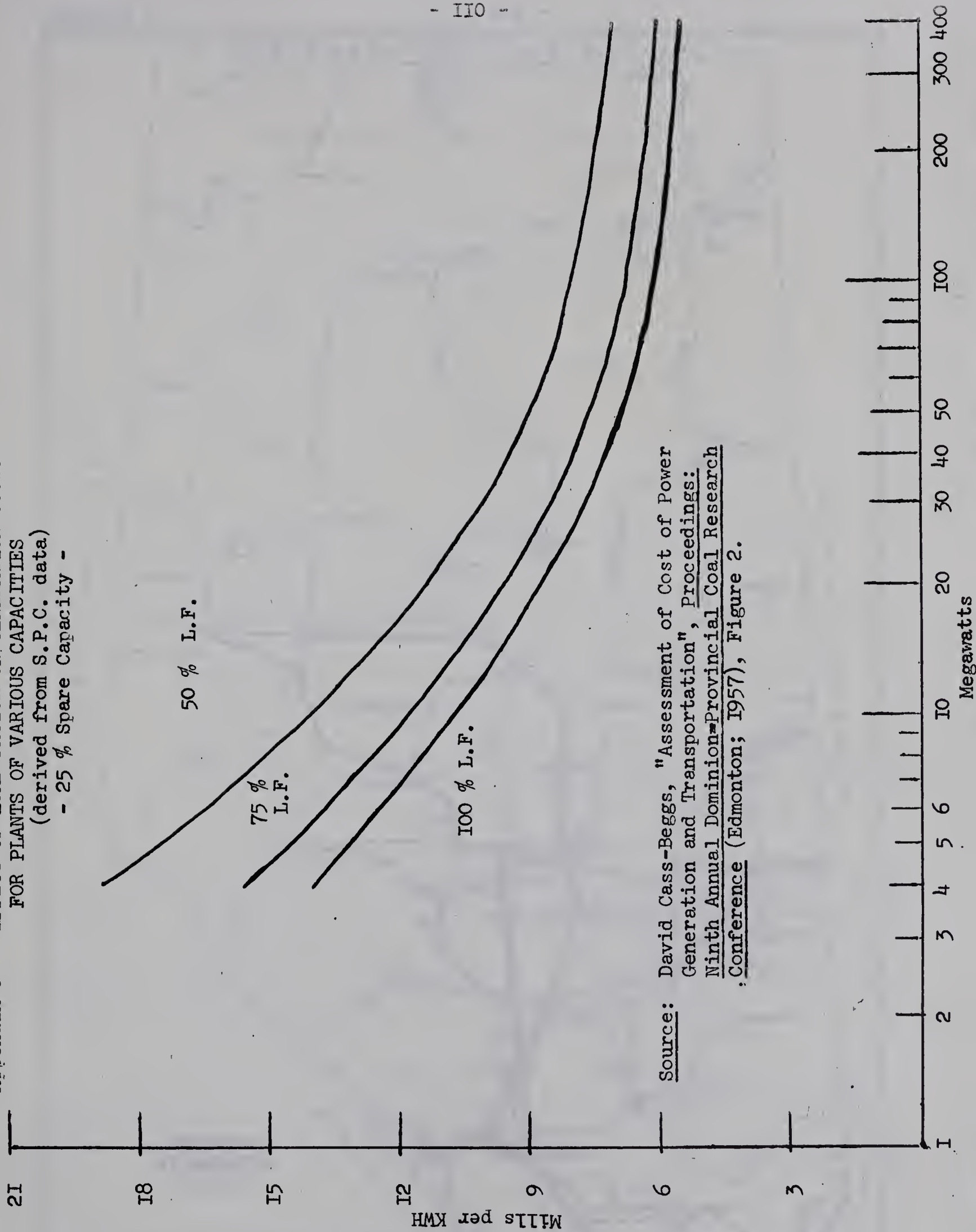

- R. L. Sanders
Manager, Western Branch.

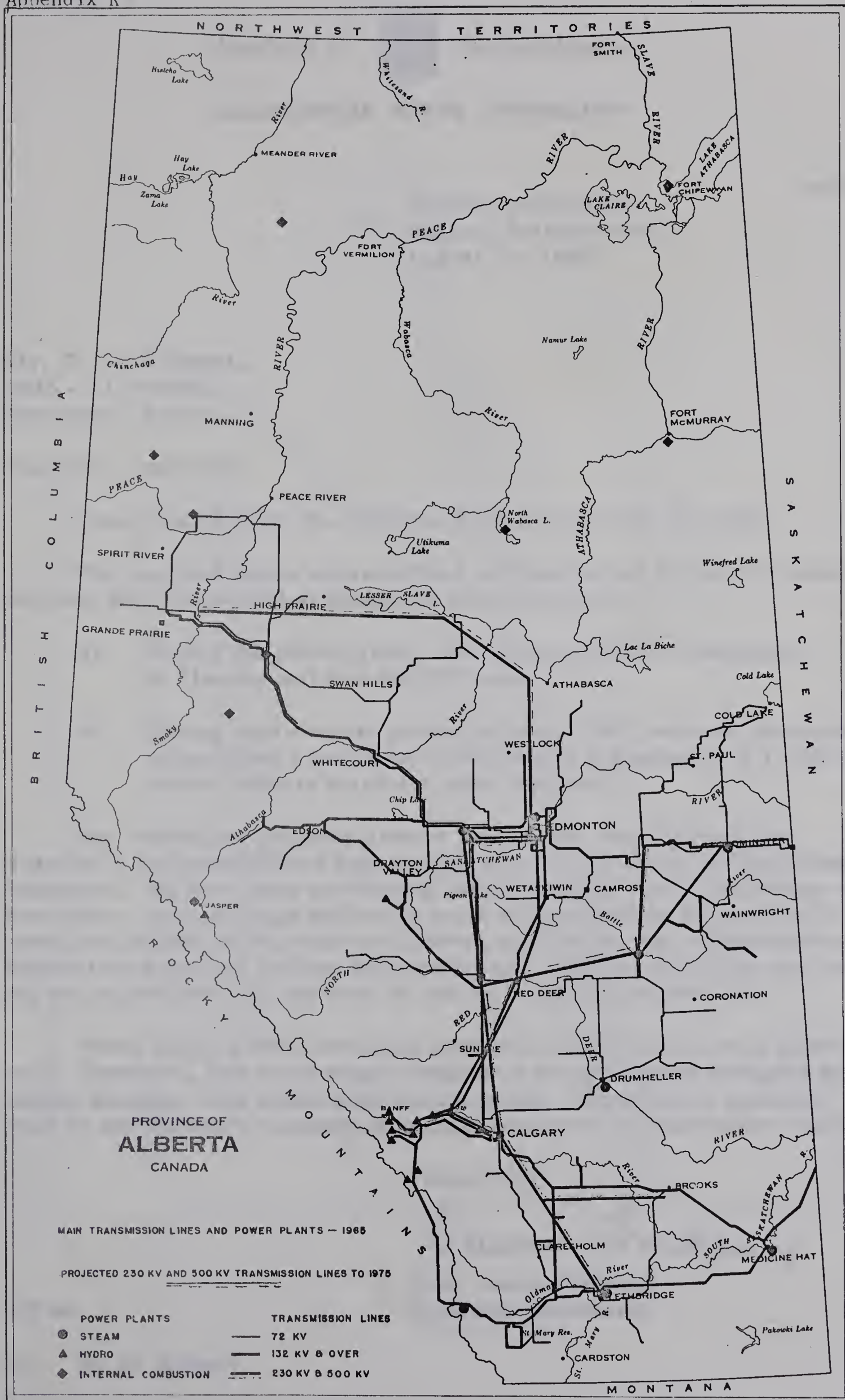
RLS*b
Encls.

Source: David Cass-Beggs, "Assessment of Cost of Power Generation and Transportation", Proceedings: Ninth Annual Dominion-Provincial Coal Research Conference (Edmonton; 1957), p. 113.



EFFECT OF LOAD FACTOR ON GENERATION COSTS
FOR PLANTS OF VARIOUS CAPACITIES
(derived from S.P.C. data)
- 25 % Spare Capacity -





Source: Courtesy of the Alberta Power Commission.

Province of Saskatchewan

SASKATCHEWAN POWER CORPORATION

OUR FILE NO.

Victoria and Scarth,
Regina, Saskatchewan,
August 12, 1965.

Mr. D. M. Paproski,
6823 - 111 Street,
Edmonton, Alberta.

Dear Mr. Paproski:

Your letter of July 26, 1965 has been given to me for reply.

The past and future consumptions of Alberta coal in our two major thermal stations located at Saskatoon are as follows:

- A. During the period June, 1960 to June, 1965, consumption of Alberta coal was 640,000 tons.
- B. During the two-year period to June, 1967, we have contracted to purchase a minimum of 500,000 to a maximum of 1,000,000 tons of Alberta slack and mine-run coal.

Our reason for utilizing Alberta coal rather than lignite from Estevan is the prohibitively high freight rate for the latter on North-South transport. We have been purchasing coal in quantity from Forestburg and Sheerness, at an average delivered price at Saskatoon of 22 cents to 24 cents per million Btu's; whereas Estevan coal would cost approximately double this price per million Btu's delivered. This is still high-cost fuel for the plants, but it is the best we can do in the circumstances.

There are, as well, technical problems involved in burning lignite coal. However, this is no major obstacle at our two plants designed for lignite burning, built at the Estevan minehead. These latter generate what is our system's cheapest electrical energy by a considerable margin.

Yours truly,

Laura Fielding

Mrs. Laura Fielding,
Research Economist.

LF:dn

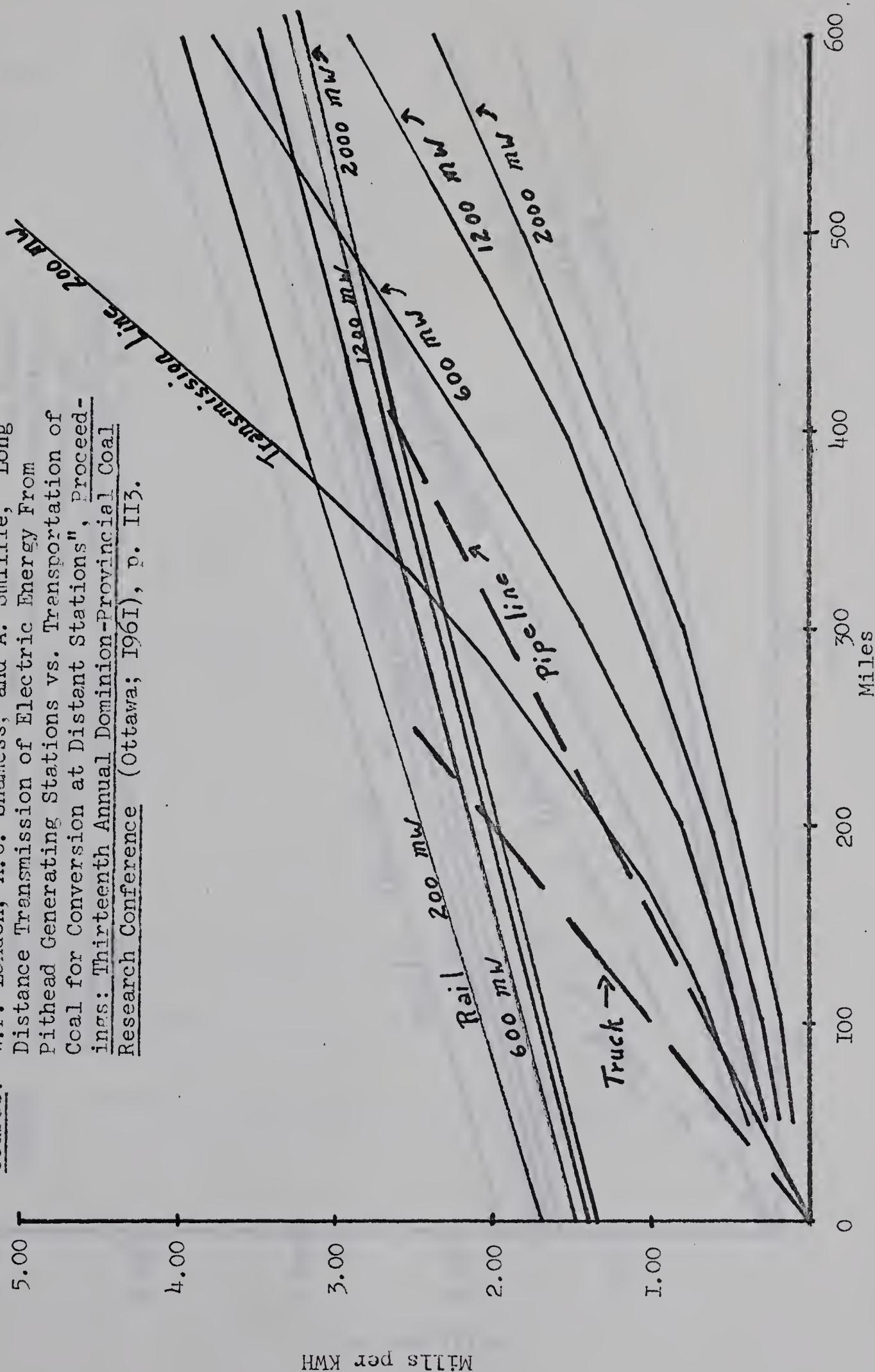
cc: B. A. Steuart

Appendix M

COSTS OF POWER TRANSMISSION AND COAL TRANSPORTATION...WESTERN CANADA

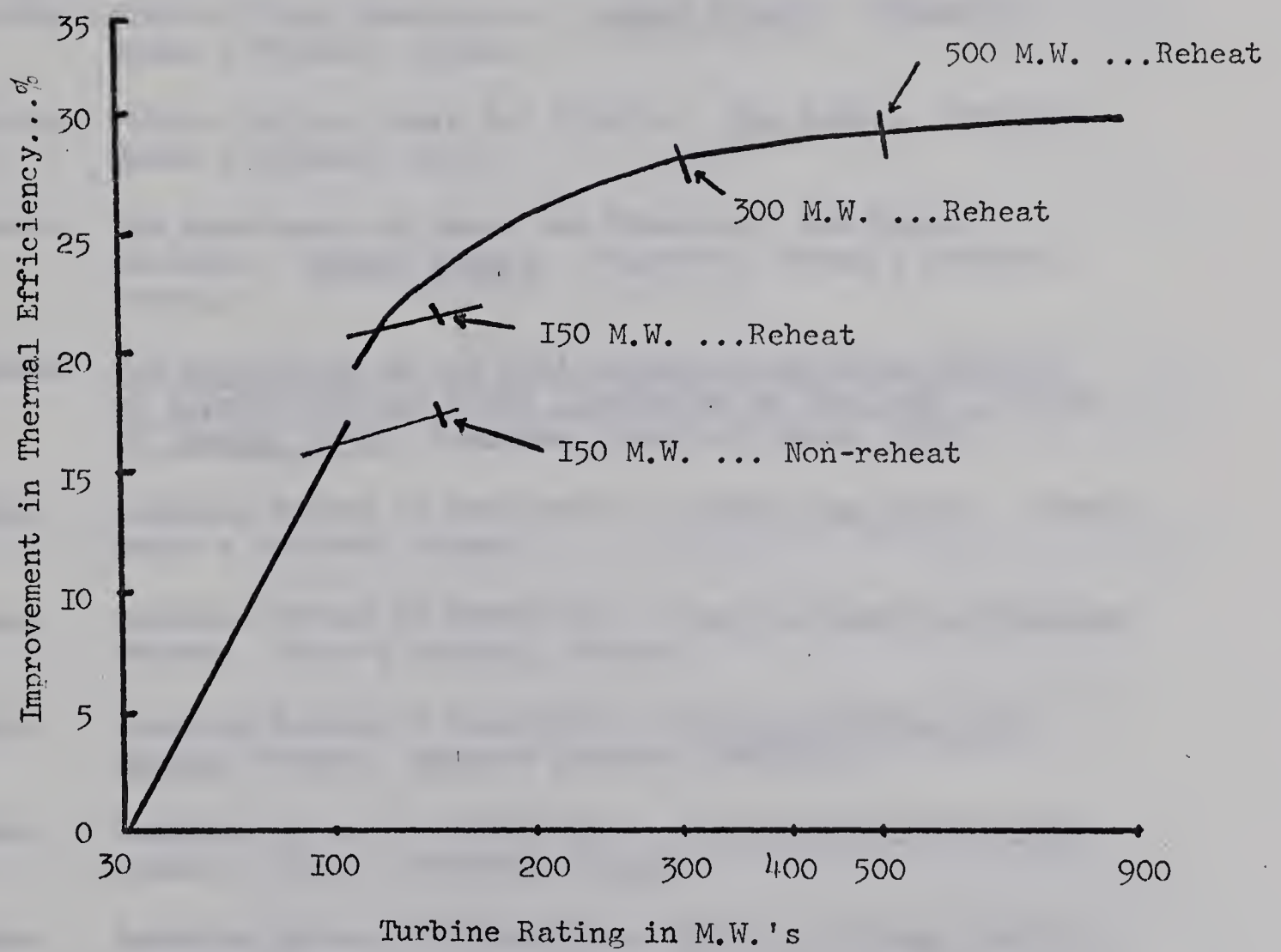
- 50 % Load Factor -

Source: W.P. London, A.C. Shames, and A. Smillie, "Long Distance Transmission of Electric Energy From Pithead Generating Stations vs. Transportation of Coal for Conversion at Distant Stations", Proceedings: Thirteenth Annual Dominion-Provincial Coal Research Conference (Ottawa; 1961), p. 113.



Appendix O

RELATIVE IMPROVEMENT IN THERMAL
EFFICIENCY WITH TURBINE RATING



Source: Courtesy of Wilson Sterling, Canadian Utilities Ltd.

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